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Filed Pursuant to Rule 424(b)(3)
Registration No. 333-164876

PROSPECTUS

Offer to Exchange
Up To $525,000,000 of
9.375% Senior Notes due 2017
That Have Not Been Registered Under
The Securities Act of 1933
For
Up To $525,000,000 of
9.375% Senior Notes due 2017
That Have Been Registered Under
The Securities Act of 1933

Terms of the New 9.375% Senior Notes due 2017 Offered in the Exchange Offer:

- The terms of the new notes are identical to the terms of the old notes that were issued on November 17, 2009 and January 19, 2010, except that the new notes will be registered under the Securities Act of 1933 and will not contain restrictions on transfer, registration rights or provisions for additional interest.

Terms of the Exchange Offer:

- We are offering to exchange up to $525,000,000 of our old notes for new notes with materially identical terms that have been registered under the Securities Act of 1933 and are freely tradable.
- We will exchange all old notes that you validly tender and do not validly withdraw before the exchange offer expires for an equal principal amount of new notes.
- The exchange offer expires at 5:00 p.m., New York City time, on July 14, 2010, unless extended.
- Tenders of old notes may be withdrawn at any time prior to the expiration of the exchange offer.
- The exchange of new notes for old notes will not be a taxable event for U.S. federal income tax purposes.
- Broker-dealers who receive new notes pursuant to the exchange offer acknowledge that they will deliver a prospectus in connection with any resale of such new notes.
- Broker-dealers who acquired the old notes as a result of market-making or other trading activities may use the prospectus for the exchange offer, as supplemented or amended, in connection with resales of the new notes.

You should carefully consider the risk factors beginning on page 10 of this prospectus before participating in

the exchange offer.

Neither the Securities and Exchange Commission nor any state securities commission has approved or disapproved of these securities or determined if this prospectus is truthful or complete. Any representation to the contrary is a criminal offense.

The date of this prospectus is June 14, 2010

This prospectus is part of a registration statement we filed with the Securities and Exchange Commission. In making your investment decision, you should rely only on the information contained in this prospectus and in the accompanying letter of transmittal. We have not authorized anyone to provide you with any other information. We are not making an offer to sell these securities or soliciting an offer to buy these securities in any jurisdiction where an offer or solicitation is not authorized or in which the person making that offer or solicitation is not qualified to do so or to anyone whom it is unlawful to make an offer or solicitation. You should not assume that the information contained in this prospectus is accurate as of any date other than its date.

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In this prospectus we refer to the notes to be issued in the exchange offer as the "new notes" or "new Notes," and we refer to the $375 million principal amount of our 9.375% senior notes due 2017 issued on November 17, 2009, together with the additional $150 million principal amount of our 9.375% senior notes due 2017 issued on January 19, 2010, as the "old notes" or "old Notes." We refer to the new notes and the old notes collectively as the "notes." In this prospectus, references to the "issuer" refer to Antero Resources Finance Corporation, a Delaware corporation and an indirect wholly owned subsidiary of Antero Resources LLC, a Delaware limited liability company. Antero Resources Finance Corporation has been formed to be the issuer of the notes. References to "Antero" or "Antero Resources" refer to Antero Resources LLC unless otherwise indicated or the context otherwise requires. References to "operating subsidiaries" refer to Antero's principal operating subsidiaries, Antero Resources Corporation, Antero Resources Midstream Corporation, Antero Resources Piceance Corporation, Antero Resources Pipeline Corporation and Antero Resources Appalachian Corporation, each of which is a Delaware corporation. References to "we," "us" or "our" refer to Antero and its subsidiaries, unless otherwise indicated or the context otherwise requires. References to "guarantors" refer to Antero and each of its subsidiaries that guarantee amounts outstanding on the notes on a joint and several basis.

This prospectus incorporates important business and financial information about us that is not included or delivered with this prospectus. Such information is available without charge to holders of old notes upon written or oral request made to Antero Resources Finance Corporation, 1625 17th Street, Denver, Colorado, 80202, Attention: Chief Financial Officer (Telephone (303) 357-7310). To obtain timely delivery of any requested information, holders of old notes must make any request no later than five business days prior to the expiration of the exchange offer.

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

The information in this prospectus includes "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended (the "Securities Act") and Section 21E of the Securities Exchange Act of 1934, as amended (the "Exchange Act"). All statements, other than statements of historical fact included in this prospectus, regarding our strategy, future operations, financial position, estimated revenues and losses, projected costs, prospects, plans and objectives of management are forward-looking statements. When used in this prospectus, the words "could," "believe," "anticipate," "intend," "estimate," "expect," "project" and similar expressions are intended to identify forward-looking statements, although not all forward-looking statements contain such identifying words. These forward-looking statements are based on our current expectations and assumptions about future events and are based on currently available information as to the outcome and timing of future events. When considering forward-looking statements, you should keep in mind the risk factors and other cautionary statements described under the heading "Risk Factors" included in this prospectus. These forward-looking statements are based on management's current belief, based on currently available information, as to the outcome and timing of future events.

Forward-looking statements may include statements about our:

- business strategy;
- reserves;
- financial strategy, liquidity and capital required for our development program;
- realized natural gas and oil prices;
- timing and amount of future production of natural gas and oil;
- hedging strategy and results;
- future drilling plans;
- competition and government regulations;
- marketing of natural gas and oil;
- leasehold or business acquisitions;
- costs of developing our properties and conducting our gathering and other midstream operations;

- general economic conditions;
- credit markets;
- liquidity and access to capital;
- uncertainty regarding our future operating results; and
- plans, objectives, expectations and intentions contained in this prospectus that are not historical.

We caution you that these forward-looking statements are subject to all of the risks and uncertainties, most of which are difficult to predict and many of which are beyond our control, incident to the exploration for and development, production, gathering and sale of natural gas and oil. These risks include, but are not limited to, commodity price volatility, inflation, lack of availability of drilling and production equipment and services, environmental risks, drilling and other operating risks, regulatory changes, the uncertainty inherent in estimating natural gas and oil reserves and in projecting future rates of production, cash flow and access to capital, the timing of development expenditures, and the other risks described under "Risk Factors" in this prospectus.

Reserve engineering is a process of estimating underground accumulations of natural gas and oil that cannot be measured in an exact way. The accuracy of any reserve estimate depends on the quality of available data, the interpretation of such data and price and cost assumptions made by reservoir engineers. In addition, the results of drilling, testing and production activities may justify revisions of estimates that were made previously. If significant, such revisions would change the schedule of any further production and development drilling. Accordingly, reserve estimates may differ significantly from the quantities of natural gas and oil that are ultimately recovered.

Should one or more of the risks or uncertainties described in this prospectus occur, or should underlying assumptions prove incorrect, our actual results and plans could differ materially from those expressed in any forward- looking statements.

All forward-looking statements, expressed or implied, included in this prospectus are expressly qualified in their entirety by this cautionary statement. This cautionary statement should also be considered in connection with any subsequent written or oral forward-looking statements that we or persons acting on our behalf may issue.

Except as otherwise required by applicable law, we disclaim any duty to update any forward-looking statements, all of which are expressly qualified by the statements in this section, to reflect events or circumstances after the date of this prospectus.

PROSPECTUS SUMMARY

This summary highlights some of the information contained in this prospectus and does not contain all of the information that may be important to you. You should read this entire prospectus and the documents to which we refer you before making an investment decision. You should carefully consider the information set forth under "Risk Factors" beginning on page 10 of this prospectus and the other cautionary statements described in this prospectus. In addition, certain statements include forward looking information that involves risks and uncertainties. See "Cautionary Statement Regarding Forward-Looking Statements." The information in this prospectus with respect to our estimated proved reserves as of December 31, 2007 and 2008 has been prepared by independent reserve engineering firms or by our internal reserve engineers, as applicable, in accordance with the rules and regulations of the SEC applicable to fiscal years ending before December 31, 2009. The information in this prospectus with respect to our estimated proved reserves as of December 31, 2009 has been prepared by our independent reserve engineering firms, in accordance with the rules and regulations of the SEC applicable to fiscal years ending on or after December 31, 2009. Certain operational terms used in this prospectus are defined in "Annex B: Glossary of Natural Gas and Oil Terms."

Our Company

Antero Resources is an independent oil and natural gas company engaged in the exploration, development and production of natural gas properties located onshore in the United States. We focus on unconventional reservoirs, which can generally be characterized as fractured shales and tight sand formations. Our properties are primarily located in the Appalachian Basin in West Virginia and Pennsylvania, the Arkoma Basin in Oklahoma and the Piceance Basin in Colorado. Our corporate headquarters are in Denver, Colorado.

Our management team has worked together for many years and has a successful track record of reserve and production growth as well as significant expertise in unconventional resource plays. Our strategy is to leverage our team's experience delineating and developing natural gas resource plays to profitably grow our reserves and production, primarily through internally generated projects on our existing acreage. As of December 31, 2009, our estimated proved reserves were 1,140.7 Bcfe, consisting of 1,130.3 Bcf of natural gas and 1.7 MMBbl of oil and condensate. As of December 31, 2009, 99% of our proved reserves were natural gas, 24% were proved developed and 69% were operated by us. From December 31, 2006 through December 31, 2009, we grew our estimated proved reserves from 87.0 Bcfe to 1,140.7 Bcfe. In addition, we grew our average daily production from 30.8 MMcfe/d for the year ended December 31, 2007 to 105.2 MMcfe/d for the year ended December 31, 2009 and to 117.8 MMcfe/d for the three months ended March 31, 2010. For the year ended December 31, 2009 and the three months ended March 31, 2010, we generated cash flow from operations of $149.3 million and $52.0 million, respectively, net income (loss) of $(106.2) million and $87.6 million, respectively, and EBITDAX of $201.3 million and $51.7 million, respectively. See "Selected Historical Combined Financial Data" for a definition of EBITDAX (a non-GAAP measure) and a reconciliation of EBITDAX to net income (loss).

We have assembled a diversified portfolio of long-lived properties that are characterized by what we believe to be low geologic risk and a large inventory of repeatable drilling opportunities. Our drilling opportunities are focused in the Marcellus Shale of the Appalachian Basin, the Woodford Shale of the Arkoma Basin (the Arkoma Woodford), the Fayetteville Shale of the Arkoma Basin and the Mesaverde tight sands and Mancos Shale of the Piceance Basin. From inception, we have drilled and operated 285 wells through December 31, 2009 with a success rate of approximately 98%. Our drilling inventory consists of approximately 16,000 potential locations, all of which are resource-style opportunities and approximately 9.8% of which are included in our estimated proved reserve base as of December 31, 2009. For information on the possible limitations on our ability to drill our potential locations, see "Risk Factors—Risks Relating to Our Business—Our identified drilling locations are scheduled out over many years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling. In addition, we may not be able to raise the substantial amount of capital that would be necessary to drill a substantial portion of our potential drilling locations."

We own two midstream systems (one in the Arkoma Basin and one in the Piceance Basin), and we believe we have secured sufficient long-term firm takeaway capacity on major pipelines that are in existence or currently under construction in each of our core operating areas to accommodate our existing and foreseeable production.

Our board of directors has approved a capital expenditure budget of up to $366 million for 2010, approximately 89% of which is allocated to drilling. Of our 2010 drilling budget, approximately 43% is allocated to the Appalachian Basin, 29% to the Arkoma Basin Woodford Shale and 28% to the Piceance Basin. Consistent with our historical practice, we periodically review our capital expenditures and adjust our budget based on liquidity, commodity prices and drilling results.

We believe we have a conservative financial position characterized by modest leverage, a strong hedge position and ample liquidity. We have entered into hedging contracts covering a total of approximately 173 Bcf of our natural gas production from April 1, 2010 through December 31, 2014 at a weighted average index price of $6.38 per Mcf. For the nine months ending December 31, 2010, we have hedged approximately 23.6 Bcf of our production at a weighted average index price of $6.13 per Mcf. On November 17, 2009, we completed an offering of $375 million principal amount of our 9.375% senior notes due 2017. On January 19, 2010, we completed an offering of $150 million additional principal amount of our 9.375% senior notes due 2017. On May 12, 2010, the borrowing base under our senior secured revolving credit facility was redetermined at $400 million (the maximum available under the facility). As of such date, after giving effect to the redetermination, we had approximately $361 million of available borrowing capacity under our senior secured revolving credit facility.

Corporate Sponsorship and Structure

We began operations in 2004, and have funded development and operating activities of each of the operating subsidiaries primarily through equity capital raised from private equity sponsors and institutional investors, through borrowings under our bank credit facilities and through internal operating cash flows. Our primary private equity sponsors are affiliates of Warburg Pincus, Yorktown Energy Partners and Trilantic Capital Partners.

Antero Resources LLC was formed as a holding company in October 2009 in connection with our corporate reorganization of the operating subsidiaries and the issuance of a new class of units in Antero in November 2009. Prior to this reorganization, all of our operations were conducted by five separately capitalized commonly controlled operating subsidiaries.

In connection with the November 2009 corporate reorganization, the stockholders of each of the operating subsidiaries contributed all of the outstanding shares of each operating subsidiary to Antero. In return, Antero issued an equivalent number of units of different classes to such stockholders. The newly issued units are substantially similar in character to the contributed stock of each operating subsidiary, including the relative priority of any distributions made by Antero as well as the vesting schedule applicable to shares held by any member of management. Simultaneously with this exchange, Antero issued a new class of units in exchange for $110 million in new equity capital. Later in November 2009, Antero issued additional units of such new class in exchange for an additional $15 million in new equity capital. We refer to these issuances in this prospectus as our November 2009 equity placements. None of Antero's outstanding units are entitled to current cash distributions or are convertible into indebtedness, and Antero has no obligation to repurchase these units at the election of the unitholders.

We used the aggregate net proceeds of approximately $124 million from the November 2009 equity placements to repay borrowings outstanding under our senior secured revolving credit facility.

Antero Resources Finance Corporation, the issuer of the notes, was formed in October 2009 as an indirect wholly owned subsidiary of Antero. The issuer was formed to arrange financing for Antero and the operating subsidiaries, including the notes. The indenture governing the notes limits the issuer's activity to those of a finance subsidiary. The issuer does not own any significant assets other than intercompany obligations. The five operating subsidiaries together own all of the outstanding common stock of the issuer. Antero owns all of the outstanding common stock of the five operating subsidiaries.

For more information on our corporate restructuring and the November 2009 equity placements, see "Business—Corporate Sponsorship and Structure."

Corporate Headquarters

Our corporate headquarters are located at 1625 17th Street, Denver, Colorado 80202, and our telephone number at that address is (303) 357-7310.

The Exchange Offer

On November 17, 2009, we completed a private offering of $375 million principal amount of the old notes. On January 19, 2010, we completed a private offering of an additional $150 million principal amount of the old notes. We entered into registration rights agreements with the initial purchasers in connection with these offerings in which we agreed to deliver to you this prospectus and to use commercially reasonable efforts to complete the exchange offer within 360 days after the date of the initial issuance of the old notes (November 17, 2009).

Exchange Offer	We are offering to exchange new notes for old notes.
Expiration Date	The exchange offer will expire at 5:00 p.m., New York City time, on July 14, 2010, unless we decide to extend it.
Condition to the Exchange Offer	The registration rights agreements do not require us to accept old notes for exchange if the exchange offer, or the making of any exchange by a holder of the old notes, would violate any applicable law or interpretation of the staff of the Securities and Exchange Commission. The exchange offer is not conditioned on a minimum aggregate principal amount of old notes being tendered.
Procedures for Tendering Old Notes	To participate in the exchange offer, you must follow the procedures established by The Depository Trust Company, which we call "DTC," for tendering notes held in book-entry form. These procedures, which we call "ATOP," require that (i) the exchange agent receive, prior to the expiration date of the exchange offer, a computer generated message known as an "agent's message" that is transmitted through DTC's automated tender offer program, and (ii) DTC confirms that: • DTC has received your instructions to exchange your notes, and • you agree to be bound by the terms of the letter of transmittal. For more information on tendering your old notes, please refer to the section in this prospectus entitled "Exchange Offer—Terms of the Exchange Offer," "—Procedures for Tendering," and "Description of Notes—Book Entry; Delivery and Form."
Guaranteed Delivery Procedures	None.
Withdrawal of Tenders	You may withdraw your tender of old notes at any time prior to the expiration date. To withdraw, you must submit a notice of withdrawal to the exchange agent using ATOP procedures before 5:00 p.m., New York City time, on the expiration date of the exchange offer. Please refer to the section in this prospectus entitled "Exchange Offer—Withdrawal of Tenders."

Acceptance of Old Notes and Delivery of New Notes	If you fulfill all conditions required for proper acceptance of old notes, we will accept any and all old notes that you properly tender in the exchange offer before 5:00 p.m. New York City time on the expiration date. We will return any old note that we do not accept for exchange to you without expense promptly after the expiration date and acceptance of the old notes for exchange. Please refer to the section in this prospectus entitled "Exchange Offer—Terms of the Exchange Offer."
Fees and Expenses	We will bear expenses related to the exchange offer. Please refer to the section in this prospectus entitled "Exchange Offer—Fees and Expenses."
Use of Proceeds	The issuance of the new notes will not provide us with any new proceeds. We are making this exchange offer solely to satisfy our obligations under our registration rights agreements.
Consequences of Failure to Exchange Old Notes	If you do not exchange your old notes in this exchange offer, you will no longer be able to require us to register the old notes under the Securities Act except in limited circumstances provided under the registration rights agreements. In addition, you will not be able to resell, offer to resell or otherwise transfer the old notes unless we have registered the old notes under the Securities Act, or unless you resell, offer to resell or otherwise transfer them under an exemption from the registration requirements of, or in a transaction not subject to, the Securities Act.
U.S. Federal Income Tax Consequences	The exchange of new notes for old notes in the exchange offer will not be a taxable event for U.S. federal income tax purposes. Please read "Material United States Federal Income Tax Consequences."
Exchange Agent	We have appointed Wells Fargo Bank, N.A. as exchange agent for the exchange offer. You should direct questions and requests for assistance, requests for additional copies of this prospectus or the letter of transmittal to the exchange agent as follows: *By Registered & Certified Mail:* Wells Fargo Bank, N.A. Corporate Trust Operations MAC N9303-121 PO Box 1517 Minneapolis, Minnesota 55480 Wells Fargo Bank, N.A.,

By regular mail or overnight courier:

Wells Fargo Bank, N.A.
Corporate Trust Operations
MAC N9303-121
Sixth & Marquette Avenue
Minneapolis, Minnesota 55479.

In person by hand only:

Wells Fargo Bank, N.A.
12th Floor—Northstar East Building
Corporate Trust Operations
608 Second Avenue South
Minneapolis, Minnesota 55402

Eligible institutions may make requests by facsimile at
(612) 667-6282 and may confirm facsimile delivery by calling
(800) 344-5128.

Terms of the New Notes

The new notes will be identical to the old notes except that the new notes are registered under the Securities Act and will not have restrictions on transfer, registration rights or provisions for additional interest. The new notes will evidence the same debt as the old notes, and the same indenture will govern the new notes and the old notes.

The following summary contains basic information about the new notes and is not intended to be complete. It does not contain all information that may be important to you. For a more complete understanding of the new notes, please refer to the section entitled "Description of Notes" in this prospectus.

Issuer	Antero Resources Finance Corporation
Securities Offered	$525 million aggregate principal amount of 9.375% senior notes due 2017.
Maturity	December 1, 2017.
Interest Payment Dates	Interest on the notes will be paid semi-annually in arrears on June 1 and December 1 and of each year commencing on June 1, 2010. Interest on each new note will accrue from the last interest payment date on which interest was paid on the old note tendered in exchange thereof, or, if no interest has been paid on the old note, from the date of the original issue of the old note.
Guarantees	The payment of the principal, premium and interest on the notes will be fully and unconditionally guaranteed on a senior unsecured basis by Antero, all of its wholly owned subsidiaries (other than the issuer) and certain of its future restricted subsidiaries. The guarantees will be unsecured senior indebtedness of the guarantors and will have the same ranking with respect to the guarantors' indebtedness as the notes will have with respect to the issuer's indebtedness. As of March 31, 2010, the only non-guarantor subsidiary of Antero, Centrahoma Processing LLC (which is 60% owned by Antero), had no outstanding indebtedness and held less than 4% of our consolidated total assets. See "Description of Notes—Guarantees."
Ranking	The new notes will be the issuer's general senior unsecured obligations. The new notes will: • rank equally in right of payment with all of the issuer's other senior indebtedness (including the issuer's guarantee under our senior secured revolving credit facility); and • rank senior in right of payment to any of the issuer's future subordinated indebtedness. The guarantees will be the guarantors' general senior unsecured obligations and will rank equally in right of payment with all of the other senior indebtedness of the guarantors.

	The notes and guarantees will effectively rank junior in right of payment to all of the issuer's and the guarantors' existing and future secured indebtedness, including indebtedness under the guarantors' senior secured revolving credit facility and capital leases, to the extent of the value of the collateral securing such indebtedness.
	As of March 31, 2010, the notes and the guarantees ranked effectively junior to approximately $11 million of senior secured indebtedness (letters of credit) outstanding under our senior secured revolving credit facility and approximately $1 million under capital leases.
Optional Redemption	The issuer will have the option to redeem the new notes, in whole or in part, at any time on or after December 1, 2013, in each case at the redemption prices described in this prospectus under the heading "Description of Notes—Optional Redemption," together with any accrued and unpaid interest to the date of such redemption.
	At any time prior to December 1, 2013, the issuer may redeem the new notes, in whole or in part, at a "make-whole" redemption price described under "Description of Notes—Optional Redemption," together with any accrued and unpaid interest to the date of such redemption.
	In addition, on or prior to December 1, 2012, the issuer may, at any time or from time to time, redeem up to 35% of the aggregate principal amount of the notes with the net proceeds of certain equity offerings at a redemption price equal to 109.375% of the principal amount of the notes, plus any accrued and unpaid interest to the date of such redemption.
Mandatory Offers to Purchase	Upon the occurrence of a change of control, unless the issuer has exercised its optional redemption right in respect of the notes, holders of the new notes will have the right to require the issuer to purchase all or a portion of the new notes at a price equal to 101% of the aggregate principal amount of the notes, together with any accrued and unpaid interest to the date of purchase. In connection with certain asset dispositions, the issuer will be required to use the net cash proceeds of the asset dispositions to make an offer to purchase the new notes at 100% of the principal amount, together with any accrued and unpaid interest to the date of purchase.
Certain Covenants	The issuer will issue the new notes under an indenture, dated as of November 17, 2009, with Wells Fargo Bank, National Association, as trustee. The indenture, among other things, limits the ability of Antero and its restricted subsidiaries to:
	• incur, assume or guarantee additional indebtedness or issue preferred stock;
	• pay dividends on equity securities, repurchase equity securities or redeem subordinated indebtedness;

- make investments or other restricted payments;
- create liens to secure indebtedness;
- restrict dividends, loans or other asset transfers from our restricted subsidiaries;
- sell or otherwise dispose of assets, including capital stock of subsidiaries;
- enter into transactions with affiliates; and
- consolidate with or merge with or into, or sell substantially all of our properties to, another person.

However, many of these covenants will terminate if:

- both Standard & Poor's Ratings Services and Moody's Investors Service, Inc. assign the notes an investment grade rating; and
- no default under the indenture has occurred and is continuing.

These covenants are subject to important exceptions and qualifications, which are described under "Description of Notes—Certain Covenants."

Transfer Restrictions; Absence of a Public Market for the New Notes	The new notes generally will be freely transferable, but will also be new securities for which there will not initially be a market. There can be no assurance as to the development or liquidity of any market for the new notes. We do not intend to apply for a listing of the new notes on any securities exchange or any automated dealer quotation system.
Risk Factors	Investing in the new notes involves risks. See "Risk Factors" beginning on page 10 for a discussion of certain factors you should consider in evaluating whether or not to tender your old notes.

RISK FACTORS

Investing in the notes involves risks. You should carefully consider the information in this prospectus, including the matters addressed under "Cautionary Statement Regarding Forward-Looking Statements," and the following risks before participating in the exchange offer.

We are subject to certain risks and hazards due to the nature of the business activities we conduct. The risks mentioned in the preceding paragraph, any of which could materially and adversely affect our business, financial condition, cash flows, and results of operations, are not the only risks we face. We may experience additional risks and uncertainties not currently known to us; or, as a result of developments occurring in the future, conditions that we currently deem to be immaterial may also materially and adversely affect our business, financial condition, cash flows, and results of operations.

Risks Relating to the Notes

If you do not properly tender your old notes, you will continue to hold unregistered old notes and your ability to transfer old notes will remain restricted and may be adversely affected.

The issuer will only issue new notes in exchange for old notes that you timely and properly tender. Therefore, you should allow sufficient time to ensure timely delivery of the old notes and you should carefully follow the instructions on how to tender your old notes. Neither we nor the exchange agent is required to tell you of any defects or irregularities with respect to your tender of old notes.

If you do not exchange your old notes for new notes pursuant to the exchange offer, the old notes you hold will continue to be subject to the existing transfer restrictions. In general, you may not offer or sell the old notes except under an exemption from, or in a transaction not subject to, the Securities Act and applicable state securities laws. We do not plan to register old notes under the Securities Act unless our registration rights agreements with the initial purchasers of the old notes require us to do so. Further, if you continue to hold any old notes after the exchange offer is consummated, you may have trouble selling them because there will be fewer of the old notes outstanding.

We may not be able to generate sufficient cash to service all of our indebtedness, including the notes, and may be forced to take other actions to satisfy our obligations under our indebtedness, which may not be successful.

Our ability to make scheduled payments on or to refinance our indebtedness obligations, including the notes, depends on our financial condition and operating performance, which is subject to prevailing economic and competitive conditions and certain financial, business and other factors beyond our control. We may not be able to maintain a level of cash flows from operating activities sufficient to permit us to pay the principal, premium, if any, and interest on our indebtedness, including the notes. In particular, the cost of raising money in the debt and equity capital markets has increased substantially over the last 18 months, while the availability of funds from those markets has diminished significantly. Also, as a result of concern about the stability of financial markets generally and the solvency of counterparties specifically, the cost of obtaining money from the credit markets has increased as many lenders and institutional investors have increased interest rates, enacted tighter lending standards and reduced and, in some cases, ceased to provide funding to borrowers.

If our cash flows and capital resources are insufficient to fund our debt service obligations, we may be forced to reduce or delay investments and capital expenditures, or to sell assets, seek additional capital or restructure or refinance our indebtedness, including the notes. Our ability to restructure or refinance our indebtedness will depend on the condition of the capital markets and our financial condition at such time. Any refinancing of our indebtedness could be at higher interest rates and may require us to comply with more onerous covenants, which could further restrict our business operations. The terms of existing or future debt instruments, including the indenture governing the notes, may restrict us from adopting some of these alternatives. In addition, any failure to make payments of interest and principal on our outstanding indebtedness on a timely basis would likely result in a reduction of our credit rating, which could harm our ability to incur additional indebtedness. In the absence of sufficient cash flows and capital resources, we could face substantial liquidity problems and might be required to dispose of material assets or operations to meet our debt service and other obligations. Our senior secured revolving credit facility and the indenture governing the notes currently restrict our ability to dispose of assets and use the proceeds from such disposition. We may not be able to consummate those dispositions, and the proceeds of any such disposition may not be adequate to meet any debt service obligations then due. These alternative measures may not be successful and may not permit us to meet our scheduled debt service obligations.

On May 12, 2010, the borrowing base under our senior secured revolving credit facility was redetermined at $400 million. Our next scheduled borrowing base redetermination is expected to occur in October 2010. In the future, we may not be able to access adequate funding under our senior secured revolving credit facility as a result of a decrease in our borrowing base due to the issuance of new indebtedness, the outcome of a subsequent semi-annual borrowing base redetermination or an unwillingness or inability on the part of our lending counterparties to meet their funding obligations and the inability of other lenders to provide additional funding to cover the defaulting lender's portion. Declines in commodity prices could result in a determination to lower the borrowing base in the future and, in such a case, we could be required to repay any indebtedness in excess of the redetermined borrowing base. As a result, we may be unable to implement our drilling and development plan, make acquisitions or otherwise carry out our business plan, which would have a material adverse effect on our financial condition and results of operations and impair our ability to service the notes.

If we are unable to comply with the restrictions and covenants in the agreements governing our notes and other indebtedness, there could be a default under the terms of these agreements, which could result in an acceleration of payment of funds that we have borrowed and would impact our ability to make principal and interest payments on the notes.

If we are unable to comply with the restrictions and covenants in the indenture governing the notes or in our senior secured revolving credit facility, or in any future debt financing agreements, there could be a default under the terms of these agreements. Our ability to comply with these restrictions and covenants, including meeting financial ratios and tests, may be affected by events beyond our control. As a result, we cannot assure you that we will be able to comply with these restrictions and covenants or meet these tests. Any default under the agreements governing our indebtedness, including a default under our senior secured revolving credit facility, that is not waived by the requisite number of lenders, and the remedies sought by the holders of such indebtedness, could prevent us from paying principal, premium, if any, and interest on the notes and substantially decrease the market value of the notes. If we are unable to generate sufficient cash flow and are otherwise unable to obtain funds necessary to meet required payments of principal, premium, if any, and interest on our indebtedness, or if we otherwise fail to comply with the various covenants, including financial and operating covenants in the instruments governing our indebtedness (including covenants in our senior secured revolving credit facility), we could be in default under the terms of these agreements. In the event of such default:

- the holders of such indebtedness could elect to declare all the funds borrowed thereunder to be immediately due and payable, together with any accrued and unpaid interest;
- the lenders under our senior secured revolving credit facility could elect to terminate their commitments thereunder, cease making further loans to us and institute foreclosure proceedings against our assets; and
- we could be forced into bankruptcy or liquidation.

If our operating performance declines, in the future we may need to obtain waivers from the requisite number of lenders under our senior secured revolving credit facility to avoid being in default. If we breach our covenants under our senior secured revolving credit facility and seek a waiver, we may not be able to obtain a waiver from the required lenders on terms that are acceptable to us, if at all. If this occurs, we would be in default under our senior secured revolving credit facility, the lenders could exercise their rights, as described above, and we could be forced into bankruptcy or liquidation. See "—Restrictions in our existing and future debt agreements could limit our growth and our ability to engage in certain activities."

The notes and the guarantees are unsecured and effectively subordinated to the rights of our secured indebtedness.

The notes and the guarantees are general unsecured senior obligations ranking effectively junior to all of our existing and future secured indebtedness, including our obligations under our senior secured revolving credit facility, to the extent of the value of the collateral securing the indebtedness. The notes and the guarantees are also effectively subordinated to any indebtedness of any non-guarantor subsidiaries.

If we were unable to repay indebtedness under our senior secured revolving credit facility, the lenders under that facility could foreclose on the pledged assets to the exclusion of holders of the notes, even if an event of default exists under the indenture governing the notes at such time. Furthermore, if the lenders foreclose and sell the pledged equity interests in any guarantor in a transaction permitted under the terms of the indenture governing the notes, then such guarantor will be released from its guarantee of the notes automatically and immediately upon such sale. In any such event, because the notes are not secured by any of such assets or by the equity interests in any such guarantor, it is possible that there would be no assets from which your claims could be satisfied or, if any assets existed, they might be insufficient to satisfy your claims in full.

If the issuer or any guarantor is declared bankrupt, becomes insolvent or is liquidated or reorganized, any of its secured indebtedness will be entitled to be paid in full from its assets or the assets of any guarantor securing that indebtedness before any payment may be made with respect to the notes or the affected guarantees. Holders of the notes will participate ratably in our remaining assets with all holders of any unsecured indebtedness that does not rank junior to the notes, based upon the respective amounts owed to each holder or creditor. In any of the foregoing events, there may not be sufficient assets to pay amounts due on the notes or the guarantees. As a result, holders of the notes would likely receive less, ratably, than holders of secured indebtedness.

We may be able to incur substantially more indebtedness, including indebtedness ranking equal to the notes and the guarantees. This could increase the risks associated with the notes.

Subject to the restrictions in the indenture governing the notes and in other instruments governing our other outstanding indebtedness (including our senior secured revolving credit facility), we may incur substantial additional indebtedness (including secured indebtedness) in the future. Although the indenture governing the notes and the instruments governing our senior secured revolving credit facility contain restrictions on the incurrence of additional indebtedness, these restrictions are subject to waiver and a number of significant qualifications and exceptions, and indebtedness incurred in compliance with these restrictions could be substantial.

If the issuer or any guarantor incurs any additional indebtedness that ranks equally with the notes (or with the guarantee thereof), including trade payables, the holders of that indebtedness will be entitled to share ratably with noteholders in any proceeds distributed in connection with any insolvency, liquidation, reorganization, dissolution or other winding-up of the issuer or such guarantor. This may have the effect of reducing the amount of proceeds paid to noteholders in connection with such a distribution. As of March 31, 2010, we had total long-term indebtedness of approximately $529 million.

Any increase in our level of indebtedness will have several important effects on our future operations, including, without limitation:

- we will have additional cash requirements in order to support the payment of interest on our outstanding indebtedness;
- increases in our outstanding indebtedness and leverage will increase our vulnerability to adverse changes in general economic and industry conditions, as well as to competitive pressure;
- depending on the levels of our outstanding indebtedness, our ability to obtain additional financing for working capital, capital expenditures, general corporate and other purposes may be limited; and
- our level of indebtedness may prevent us from engaging in certain transactions that might otherwise be beneficial to us by.

Any of these factors could result in a material adverse effect on our business, financial condition, results of operations, business prospects and ability to satisfy our obligations under the notes.

Restrictions in our existing and future debt agreements could limit our growth and our ability to engage in certain activities.

Our senior secured revolving credit facility contains a number of significant covenants (in addition to covenants restricting the incurrence of additional indebtedness). Our senior secured revolving credit facility contains restrictive covenants that may limit our ability to, among other things:

- sell assets;
- make loans to others;
- make investments;
- enter into mergers;
- make certain payments;
- incur liens; and
- engage in certain other transactions without the prior consent of the lenders.

The indenture governing the notes contains similar restrictive covenants. In addition, our senior secured revolving credit facility requires us to maintain certain financial ratios or to reduce our indebtedness if we are unable to comply with such ratios. These restrictions, together with those in the indenture governing the notes, may also limit our ability to obtain future financings to withstand a future downturn in our business or the economy in general, or to otherwise conduct necessary corporate activities. We may also be prevented from taking advantage of business opportunities that arise because of the limitations that the restrictive covenants under the indenture governing the notes and our senior secured revolving credit facility impose on us.

Our senior secured revolving credit facility limits the amounts we can borrow up to a borrowing base amount, which the lenders, in their sole discretion, determine on a semi-annual basis based upon projected revenues from the natural gas properties securing our loan. The lenders can unilaterally adjust the borrowing base and the borrowings permitted to be outstanding under our senior secured revolving credit facility. Any increase in the borrowing base requires the consent of the lenders holding 100% of the commitments. If the requisite number of lenders do not agree to an increase, then the borrowing base will be the lowest borrowing base acceptable to such lenders. Outstanding borrowings in excess of the borrowing base must be repaid, or we must pledge other natural gas properties as additional collateral. We do not currently have any substantial unpledged properties, and we may not have the financial resources in the future to make mandatory principal prepayments required under our senior secured revolving credit facility. On May 12, 2010, the borrowing base under our senior secured revolving credit facility was redetermined at $400 million. Our next scheduled borrowing base redetermination is expected to occur in October 2010.

A breach of any covenant in our senior secured revolving credit facility would result in a default under that agreement after any applicable grace periods. A default, if not waived, could result in acceleration of the indebtedness outstanding under the facility and in a default with respect to, and an acceleration of, the indebtedness outstanding under other debt agreements. The accelerated indebtedness would become immediately due and payable. If that occurs, we may not be able to make all of the required payments or borrow sufficient funds to refinance such indebtedness. Even if new financing were available at that time, it may not be on terms that are acceptable to us. See "Management's Discussion and Analysis of Financial Condition and Results of Operations—Capital Resources and Liquidity—Cash Flow Provided by Financing Activities—Senior Secured Revolving Credit Facility" and "Description of Notes—Events of Default."

Our ability to repay our indebtedness, including the notes, is dependent on the cash flow generated by our operating subsidiaries.

The operating subsidiaries own substantially all of our assets and conduct all of our operations. Accordingly, repayment of our indebtedness, including the notes, will be dependent on the generation of cash flow by the operating subsidiaries and their ability to make such cash available to the issuer, directly or indirectly, by dividend, debt repayment or otherwise. All of the five operating subsidiaries guarantee the issuer's obligations under the notes. Unless they guarantee the notes, neither Centrahoma Processing LLC nor any of our future subsidiaries will have any obligation to pay amounts due on the notes or to make funds available for that purpose. The operating subsidiaries may not be able to or may not be permitted to, make distributions to enable the issuer to make payments in respect of its indebtedness, including the notes. Each operating subsidiary is a distinct legal entity and, under certain circumstances, legal and contractual restrictions may limit the issuer's ability to obtain cash from the operating subsidiaries. While the indenture governing the notes limits the ability of the operating subsidiaries to incur consensual encumbrances or restrictions on their ability to pay dividends or make other intercompany payments to Antero, those limitations are subject to waiver and certain qualifications and exceptions.

Your ability to transfer the notes may be limited by the absence of an active trading market, and there is no assurance that any active trading market will develop for the notes.

The old notes have not been registered under the Securities Act, and may not be resold by holders thereof unless the old notes are subsequently registered or an exemption from the registration requirements of the Securities Act is available. However, we cannot assure you that, even following registration or exchange of the old notes for new notes, an active trading market for the old notes or the new notes will exist, and we will have no obligation to create such a market. At the time of the private placements of the old notes, the initial purchasers advised us that they intended to make a market in the old notes and, if issued, the new notes. The initial purchasers are not obligated, however, to make a market in the old notes or the new notes and any market making may be discontinued at any time at their sole discretion. No assurance can be given as to the liquidity of or trading market for the old notes or the new notes.

The liquidity of any trading market for the notes and the market prices quoted for the notes depend upon the number of holders of the notes, the overall market for high yield securities, our financial performance or prospects or the prospects for companies in our industry generally, the interest of securities dealers in making a market in the notes and other factors.

The issuer may not be able to repurchase the notes in certain circumstances.

Under the terms of the indenture governing the notes, you may require us to repurchase all or a portion of your notes if we sell certain assets or in the event of a change of control. We may not have enough funds to pay the repurchase price on a purchase date (in which case, we could be required to issue equity securities to pay the repurchase price). Our existing and any future credit facilities or other debt agreements to which we become a party may provide that our obligation to repurchase the notes would be an event of default under such agreement. As a result, we may be restricted or prohibited from repurchasing the notes. If we are prohibited from repurchasing the notes, we could seek the consent of our then-existing lenders to repurchase the notes or we could attempt to refinance the borrowings that contain such prohibition. If we are unable to obtain any such consent or refinance such borrowings, we would not be able to repurchase the notes. Our failure to repurchase tendered notes would constitute a default under the indenture governing the notes and might constitute a default under the terms of our existing or future indebtedness.

In a recent decision, the Chancery Court of the State of Delaware raised the possibility that a change of control put right occurring as a result of a failure to have "continuing directors" comprising a majority of a board of directors may be unenforceable on public policy grounds.

The term "change of control" is limited to certain specified transactions and may not include other events that might adversely affect our financial condition. Our obligation to repurchase the notes upon a change of control would not necessarily afford holders of notes protection in the event of a highly leveraged transaction, reorganization, merger or similar transaction.

Any guarantees of the notes by Antero or the operating subsidiaries could be deemed fraudulent conveyances under certain circumstances, and a court may subordinate or void the guarantees.

Antero and the operating subsidiaries are the initial guarantors of the notes. In certain circumstances, any of Antero's future subsidiaries may be required to guarantee the notes. A court could subordinate or void the guarantees under various fraudulent conveyance or fraudulent transfer laws. Generally, to the extent that a U.S. court were to find that at the time the guarantee was entered into:

- the guarantee was incurred with the intent to hinder, delay, or defraud any present or future creditor, or contemplated insolvency with a design to favor one or more creditors to the exclusion of others; or
- the guarantor did not receive fair consideration or reasonably equivalent value for issuing the guarantee and, at the time the guarantor issued the guarantee, it:
  - was insolvent or became insolvent as a result of issuing the guarantee,
  - was engaged or about to engage in a business or transaction for which its remaining assets constituted unreasonably small capital, or
  - intended to incur, or believed that it would incur, debts beyond its ability to pay those debts as they matured;

then the court could void or subordinate the guarantees in favor of the guarantor's other obligations.

A legal challenge of a guarantee on fraudulent conveyance grounds may focus, among other things, on the benefits, if any, the guarantor realized as a result of our issuing the notes. To the extent a guarantee is voided as a fraudulent conveyance or held unenforceable for any other reason, the holders of the notes would not have any claim against that guarantor and would be creditors solely of the issuer and any other guarantors whose guarantees are not held unenforceable.

The measures of insolvency for purposes of fraudulent transfer laws vary depending upon the governing law. Generally, a guarantor would be considered insolvent if:

- the sum of its debts, including contingent liabilities, was greater than the fair saleable value of all its assets;
- the present fair saleable value of its assets was less than the amount that would be required to pay its probable liability on its existing debts, including contingent liabilities, as they became absolute and mature; or
- it could not pay its debts as they became due.

Each guarantee contains a provision intended to limit the guarantor's liability to the maximum amount that it could incur without causing the incurrence of obligations under its guarantee to be a fraudulent conveyance or fraudulent transfer. This provision may not be effective to protect the guarantees from being voided under applicable law.

Many of the covenants contained in the indenture governing the notes will terminate if the notes are rated investment grade by both Standard & Poor's Ratings Services and Moody's Investors Service, Inc.

Many of the covenants in the indenture governing the notes will terminate if the notes are rated investment grade by both Standard & Poor's Ratings Services and Moody's Investors Service, Inc., provided at such time no default under the indenture governing the notes has occurred and is continuing. These covenants will restrict, among other things, our ability to pay dividends, to incur indebtedness and to enter into certain other transactions. There can be no assurance that the notes will ever be rated investment grade, or that if they are rated investment grade, that the notes will maintain such ratings. However, termination of these covenants would allow us to engage in certain transactions that would not be permitted while these covenants were in force. See "Description of Notes—Covenant Termination."

Risks Relating to Our Business

Natural gas prices are volatile. A substantial or extended decline in natural gas prices may adversely affect our business, financial condition or results of operations and our ability to meet our capital expenditure obligations and financial commitments.

The prices we receive for our natural gas production heavily influence our revenue, profitability, access to capital and future rate of growth. Natural gas is a commodity and, therefore, its prices are subject to wide fluctuations in response to relatively minor changes in supply and demand. Historically, the market for natural gas has been volatile. This market will likely continue to be volatile in the future. The prices we receive for our production, and the levels of our production, depend on numerous factors beyond our control. These factors include the following:

- worldwide and regional economic conditions impacting the global supply and demand for natural gas;
- the price and quantity of imports of foreign natural gas, including liquefied natural gas;
- political conditions in or affecting other natural gas-producing countries, including the current conflicts in the Middle East and conditions in South America and Russia;
- the level of global natural gas exploration and production;
- the level of global natural gas inventories;
- prevailing prices on local natural gas price indexes in the areas in which we operate;
- localized and global supply and demand fundamentals and transportation availability;

- weather conditions;
- technological advances affecting energy consumption;
- the price and availability of alternative fuels; and
- domestic, local and foreign governmental regulation and taxes.

Furthermore, the current worldwide financial and credit crisis has reduced the availability of liquidity and credit to fund the continuation and expansion of industrial business operations worldwide. The shortage of liquidity and credit combined with recent substantial losses in worldwide equity markets has lead to a worldwide economic recession. The slowdown in economic activity caused by such recession has reduced worldwide demand for energy and resulted in lower natural gas prices. Natural gas spot prices have recently been particularly volatile and declined from record high levels in early July 2008 of over $13.00 per Mcf to below $4.00 per Mcf in September 2009.

Lower natural gas prices will reduce our cash flows and borrowing ability. We may be unable to obtain needed capital or financing on satisfactory terms, which could lead to a decline in our natural gas reserves as existing reserves are depleted. Lower natural gas prices may also reduce the amount of natural gas that we can produce economically.

Substantial decreases in natural gas prices would render uneconomic a significant portion of our exploration, development and exploitation projects. This may result in our having to make significant downward adjustments to our estimated proved reserves. As a result, a substantial or extended decline in natural gas prices may materially and adversely affect our future business, financial condition, results of operations, liquidity or ability to finance planned capital expenditures.

Our exploration, development and exploitation projects require substantial capital expenditures. We may be unable to obtain required capital or financing on satisfactory terms, which could lead to a decline in our natural gas reserves.

The natural gas industry is capital intensive. We make and expect to continue to make substantial capital expenditures for the development, exploitation, production and acquisition of natural gas reserves. Our cash flow used in investing activities related to capital and exploration expenditures was approximately $282 million in 2009. Our capital expenditure budget for 2010 is $366 million, with approximately $326 million allocated for drilling and completion operations. We expect to fund these capital expenditures with cash generated by operations and through borrowings under our senior secured revolving credit facility. The actual amount and timing of our future capital expenditures may differ materially from our estimates as a result of, among other things, commodity prices, actual drilling results, the availability of drilling rigs and other services and equipment, and regulatory, technological and competitive developments. A reduction in commodity prices from current levels may result in a decrease in our actual capital expenditures. Conversely, a significant improvement in product prices could result in an increase in our capital expenditures. We intend to finance our future capital expenditures primarily through cash flow from operations and through borrowings under our senior secured revolving credit facility; however, our financing needs may require us to alter or increase our capitalization substantially through the issuance of debt or equity securities or the sale of assets. The issuance of additional indebtedness may require that a portion of our cash flow from operations be used for the payment of interest and principal on our indebtedness, thereby reducing our ability to use cash flow from operations to fund working capital, capital expenditures and acquisitions.

Our cash flow from operations and access to capital are subject to a number of variables, including:

- our proved reserves;
- the level of natural gas we are able to produce from existing wells;

- the prices at which our natural gas is sold;
- our ability to acquire, locate and produce new reserves; and
- the ability of our banks to lend.

If our revenues or the borrowing base under our senior secured revolving credit facility decrease as a result of lower natural gas prices, operating difficulties, declines in reserves or for any other reason, we may have limited ability to obtain the capital necessary to sustain our operations at current levels. If additional capital is needed, we may not be able to obtain debt or equity financing on terms acceptable to us, if at all. If cash flow generated by our operations or available borrowings under our senior secured revolving credit facility are not sufficient to meet our capital requirements, the failure to obtain additional financing could result in a curtailment of our operations relating to development of our properties, which in turn could lead to a decline in our reserves, and could adversely affect our business, financial condition and results of operations.

Drilling for and producing natural gas are high risk activities with many uncertainties that could adversely affect our business, financial condition or results of operations.

Our future financial condition and results of operations will depend on the success of our exploitation, exploration, development and production activities. Our natural gas exploration, exploitation, development and production activities are subject to numerous risks beyond our control, including the risk that drilling will not result in commercially viable natural gas production. Our decisions to purchase, explore, develop or otherwise exploit prospects or properties will depend in part on the evaluation of data obtained through geophysical and geological analyses, production data and engineering studies, the results of which are often inconclusive or subject to varying interpretations. For a discussion of the uncertainty involved in these processes, see "—Reserve estimates depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves." In addition, our cost of drilling, completing and operating wells is often uncertain before drilling commences.

Further, many factors may curtail, delay or cancel our scheduled drilling projects, including the following:

- delays imposed by or resulting from compliance with regulatory requirements;
- pressure or irregularities in geological formations;
- shortages of or delays in obtaining equipment and qualified personnel;
- equipment failures or accidents;
- adverse weather conditions, such as blizzards and ice storms;
- declines in natural gas prices;
- limited availability of financing at acceptable rates;
- title problems; and
- limitations in the market for natural gas.

Our estimates of proved reserves at December 31, 2009 have been prepared under new SEC rules that went into effect for fiscal years ending on or after December 31, 2009. The new SEC rules could limit our ability to book additional proved undeveloped reserves in the future.

This prospectus includes estimates of our proved reserves as of December 31, 2009, which have been prepared and presented under the SEC's new rules relating to the reporting of oil and natural gas exploration activities. These new rules are effective for fiscal years ending on or after December 31, 2009, and require that, subject to limited exceptions, proved undeveloped reserves may only be booked if they relate to wells scheduled to be drilled within five years of the date of booking. This new rule has limited and may continue to limit our potential to book additional proved undeveloped reserves as we pursue our drilling program. Moreover, we may be required to write down any proved undeveloped reserves that are not developed within the required five-year timeframe.

The SEC has released only limited interpretive guidance regarding reporting of reserve estimates under the new rules and may not issue further interpretive guidance on the new rules. Accordingly, while the estimates of our proved reserves at December 31, 2009 included in this prospectus have been prepared based on what we and our independent reserve engineers believe to be reasonable interpretations of the new SEC rules, those estimates could differ materially from any estimates we might prepare applying more specific SEC interpretive guidance.

Reserve estimates depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves.

The process of estimating natural gas and oil reserves is complex. It requires interpretations of available technical data and many assumptions, including assumptions relating to current and future economic conditions and commodity prices. Any significant inaccuracies in these interpretations or assumptions could materially affect our estimated quantities and present value of our reserves. See "Business—Our Operations—Estimated Proved Reserves" for information about our estimated natural gas and oil reserves and the PV-10 and standardized measure of discounted future net cash flows.

In order to prepare our estimates, we must project production rates and timing of development expenditures. We must also analyze available geological, geophysical, production and engineering data. The extent, quality and reliability of this data can vary. The process also requires economic assumptions about matters such as natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds.

Actual future production, natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable natural gas reserves will vary from our estimates. Any significant variance could materially affect the estimated quantities and present value of our reserves. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development, prevailing commodity prices and other factors, many of which are beyond our control.

You should not assume that the present value of future net revenues from our proved reserves is the current market value of our estimated natural gas reserves. We generally base the estimated discounted future net cash flows from our proved reserves on prices and costs on the date of the estimate. Actual future prices and costs may differ materially from those used in the present value estimate.

Our identified drilling locations are scheduled out over many years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling. In addition, we may not be able to raise the substantial amount of capital that would be necessary to drill a substantial portion of our potential drilling locations.

Our management team has specifically identified and scheduled certain drilling locations as an estimation of our future multi-year drilling activities on our existing acreage. These drilling locations represent a significant part of our growth strategy. Our ability to drill and develop these locations depends on a number of uncertainties, including natural gas and oil prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, drilling results, lease expirations, gathering system and pipeline transportation constraints, regulatory approvals and other factors. Because of these uncertain factors, we do not know if the numerous potential drilling locations we have identified will ever be drilled or if we will be able to produce natural gas or oil from these or any other potential drilling locations. In addition, unless production is established within the spacing units covering the undeveloped acres on which some of the potential locations are obtained, the leases for such acreage will expire. As such, our actual drilling activities may materially differ from those presently identified.

We have approximately 16,000 potential drilling locations. As a result of the limitations described above, we may be unable to drill many of our potential resource play drilling locations. In addition, we will require significant additional capital over a prolonged period in order to pursue the development of these locations, and we may not be able to raise or generate the capital required to do so. Any drilling activities we are able to conduct on these potential locations may not be successful or result in our ability to add additional proved reserves to our overall proved reserves or may result in a downward revision of our estimated proved reserves, which could have a material adverse effect on our future business and results of operations.

In addition, the acquisition agreement relating to the purchase of our properties in the Appalachian Basin in 2008 contains various drilling commitments that may require us to spend up to an estimated $625 million between January 1, 2009 and June 30, 2018 at structured intervals. If we do not fulfill our drilling commitments, title to portions of the properties we purchased may revert to the seller, which could have a material adverse effect on our future business and results of operations.

If commodity prices decrease, we may be required to take write-downs of the carrying values of our properties.

Accounting rules require that we periodically review the carrying value of our properties for possible impairment. Based on specific market factors and circumstances at the time of prospective impairment reviews, and the continuing evaluation of development plans, production data, economics and other factors, we may be required to write down the carrying value of our properties. A write-down constitutes a non-cash charge to earnings. We may incur impairment charges in the future, which could have a material adverse effect on our results of operations for the periods in which such charges are taken.

Unless we replace our natural gas reserves, our reserves and production will decline, which would adversely affect our future cash flows and results of operations.

Producing natural gas reservoirs generally are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Unless we conduct successful ongoing exploration, development and exploitation activities or continually acquire properties containing proved reserves, our proved reserves will decline as those reserves are produced. Our future natural gas reserves and production, and therefore our future cash flow and results of operations, are highly dependent on our success in efficiently developing and exploiting our current reserves and economically finding or acquiring additional recoverable reserves. We may not be able to develop, exploit, find or acquire sufficient additional reserves to replace our current and future production. If we are unable to replace our current and future production, the value of our reserves will decrease, and our business, financial condition and results of operations would be adversely affected.

Currently, we receive significant incremental cash flows as a result of our hedging activity. To the extent we are unable to obtain future hedges at effective prices consistent with those we have received to date and natural gas prices do not improve, our cash flows may be adversely impacted.

To achieve more predictable cash flows and reduce our exposure to downward price fluctuations, we have entered into a number of hedge contracts for approximately 173 Bcf of our natural gas production from April 1, 2010 through December 2014. We are currently realizing a significant benefit from these hedge positions. For example, for the year ended December 31, 2009, we received approximately $116.5 million in cash flows pursuant to our hedges. If future natural gas prices remain comparable to current prices, we expect that this benefit will decline materially over the life of the hedges, which cover decreasing volumes at declining prices through December 2014. If we are unable to enter into new hedge contracts in the future at favorable pricing and for a sufficient amount of our production, our financial condition and results of operations could be materially adversely affected. For additional information regarding our hedging activities, please see "Management's Discussion and Analysis of Financial Condition and Results of Operations—Commodity Hedging Activities."

Our derivative activities could result in financial losses or could reduce our earnings.

To achieve more predictable cash flows and reduce our exposure to adverse fluctuations in the prices of natural gas, we enter into derivative instrument contracts for a portion of our natural gas production, including collars and price-fix swaps. Accordingly, our earnings may fluctuate significantly as a result of changes in fair value of our derivative instruments.

Derivative instruments also expose us to the risk of financial loss in some circumstances, including when:

- production is less than the volume covered by the derivative instruments;
- the counter-party to the derivative instrument defaults on its contractual obligations;
- there is an increase in the differential between the underlying price in the derivative instrument and actual prices received; or
- there are issues with regard to legal enforceability of such instruments.

The use of derivatives may, in some cases, require the posting of cash collateral with counterparties. If we enter into derivative instruments that require cash collateral and commodity prices or interest rates change in a manner adverse to us, our cash otherwise available for use in our operations would be reduced which could limit our ability to make future capital expenditures and make payments on our indebtedness, including the notes, and which could also limit the size of our borrowing base. Future collateral requirements will depend on arrangements with our counterparties, highly volatile oil and natural gas prices and interest rates.

As of March 31, 2010, our receivables from our derivatives counterparties were approximately $139.9 million. Any default by these counterparties on their obligations to us would have a material adverse effect on our financial condition and results of operations.

In addition, derivative arrangements could limit the benefit we would receive from increases in the prices for natural gas, which could also have an adverse effect on our financial condition.

The inability of our significant customers to meet their obligations to us may adversely affect our financial results.

In addition to credit risk related to receivables from commodity derivative contracts, our principal exposures to credit risk are through joint interest receivables ($4.9 million at March 31, 2010) and the sale of our natural gas production ($22.6 million in receivables at March 31, 2010), which we market to energy marketing companies, refineries and affiliates. Joint interest receivables arise from billing entities who own partial interest in the wells we operate. These entities participate in our wells primarily based on their ownership in leases on which we wish to drill. We can do very little to choose who participates in our wells. We are also subject to credit risk due to concentration of our natural gas receivables with several significant customers. The largest purchaser of our natural gas during the twelve months ended December 31, 2009 purchased approximately 44% of our operated production. We do not require our customers to post collateral. The inability or failure of our significant customers to meet their obligations to us or their insolvency or liquidation may adversely affect our financial results.

We may incur substantial losses and be subject to substantial liability claims as a result of our operations. Additionally we may not be insured for, or our insurance may be inadequate to protect us against, these risks.

We are not insured against all risks. Losses and liabilities arising from uninsured and underinsured events could materially and adversely affect our business, financial condition or results of operations. Our natural gas exploration and production activities are subject to all of the operating risks associated with drilling for and producing natural gas, including the possibility of:

- environmental hazards, such as uncontrollable flows of oil, natural gas, brine, well fluids, toxic gas or other pollution into the environment, including groundwater and shoreline contamination;
- abnormally pressured formations;
- mechanical difficulties, such as stuck oilfield drilling and service tools and casing collapse;
- fires, explosions and ruptures of pipelines;
- personal injuries and death;
- natural disasters; and
- terrorist attacks targeting natural gas and oil related facilities and infrastructure.

Any of these risks could adversely affect our ability to conduct operations or result in substantial losses to us as a result of:

- injury or loss of life;
- damage to and destruction of property, natural resources and equipment;
- pollution and other environmental damage;
- regulatory investigations and penalties;
- suspension of our operations; and
- repair and remediation costs.

We may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks generally are not fully insurable. The occurrence of an event that is not fully covered by insurance could have a material adverse effect on our business, financial condition and results of operations.

Prospects that we decide to drill may not yield natural gas or oil in commercially viable quantities.

Prospects that we decide to drill that do not yield natural gas or oil in commercially viable quantities will adversely affect our results of operations and financial condition. In this prospectus, we describe some of our current prospects and our plans to explore those prospects. Our prospects are in various stages of evaluation, ranging from a prospect which is ready to drill to a prospect that will require substantial additional seismic data processing and interpretation. There is no way to predict in advance of drilling and testing whether any particular prospect will yield natural gas or oil in sufficient quantities to recover drilling or completion costs or to be economically viable. The use of seismic data and other technologies and the study of producing fields in the same area will not enable us to know conclusively prior to drilling whether natural gas or oil will be present or, if present, whether natural gas or oil will be present in commercial quantities. We cannot assure you that the analogies we draw from available data from other wells, more fully explored prospects or producing fields will be applicable to our drilling prospects. Further, our drilling operations may be curtailed, delayed or cancelled as a result of numerous factors, including:

- unexpected drilling conditions;
- title problems;
- pressure or lost circulation in formations;
- equipment failure or accidents;
- adverse weather conditions;
- compliance with environmental and other governmental or contractual requirements; and
- increase in the cost of, shortages or delays in the availability of, electricity, supplies, materials, drilling or workover rigs, equipment and services.

Our use of 2-D and 3-D seismic data is subject to interpretation and may not accurately identify the presence of natural gas, which could adversely affect the results of our drilling operations.

Even when properly used and interpreted, 2-D and 3-D seismic data and visualization techniques are only tools used to assist geoscientists in identifying subsurface structures and hydrocarbon indicators and do not enable geoscientists to know whether hydrocarbons are, in fact, present in those structures and the amount of hydrocarbons. We are employing 3-D seismic technology with respect to certain of our projects. The implementation and practical use of 3-D seismic technology is relatively new, unproven and unconventional, which can lessen its effectiveness, at least in the near term, and increase our costs. In addition, the use of 3-D seismic and other advanced technologies requires greater pre-drilling expenditures than traditional drilling strategies, and we could incur greater drilling and exploration expenses as a result of such expenditures, which may result in a reduction in our returns or losses. As a result, our drilling activities may not be successful or economical, and our overall drilling success rate or our drilling success rate for activities in a particular area could decline.

We often gather 3-D seismic data over large areas. Our interpretation of seismic data delineates those portions of an area that we believe are desirable for drilling. Therefore, we may choose not to acquire option or lease rights prior to acquiring seismic data, and, in many cases, we may identify hydrocarbon indicators before seeking option or lease rights in the location. If we are not able to lease those locations on acceptable terms, we will have made substantial expenditures to acquire and analyze 3-D data without having an opportunity to attempt to benefit from those expenditures.

Market conditions or operational impediments may hinder our access to natural gas and oil markets or delay our production.

Market conditions or the unavailability of satisfactory natural gas and oil transportation arrangements may hinder our access to natural gas and oil markets or delay our production. The availability of a ready market for our natural gas and oil production depends on a number of factors, including the demand for and supply of natural gas and oil and the proximity of reserves to pipelines and terminal facilities. Our ability to market our production depends in substantial part on the availability and capacity of gathering systems, pipelines and processing facilities owned and operated by third parties. Our failure to obtain such services on acceptable terms could materially harm our business. We may be required to shut in wells due to lack of a market or inadequacy or unavailability of natural gas and oil pipeline or gathering system capacity. In addition, if natural gas or oil quality specifications for the third party natural gas or oil pipelines with which we connect change so as to restrict our ability to transport natural gas or oil, our access to natural gas and oil markets could be impeded. If our production becomes shut in for any of these or other reasons, we would be unable to realize revenue from those wells until other arrangements were made to deliver the products to market.

We are subject to complex federal, state, local and other laws and regulations that could adversely affect the cost, manner or feasibility of conducting our operations or expose us to significant liabilities.

Our natural gas exploration, production and transportation operations are subject to complex and stringent laws and regulations. In order to conduct our operations in compliance with these laws and regulations, we must obtain and maintain numerous permits, approvals and certificates from various federal, state and local governmental authorities. We may incur substantial costs in order to maintain compliance with these existing laws and regulations. In addition, our costs of compliance may increase if existing laws and regulations are revised or reinterpreted, or if new laws and regulations become applicable to our operations. Such costs could have a material adverse effect on our business, financial condition and results of operations.

Our business is subject to federal, state and local laws and regulations as interpreted and enforced by governmental authorities possessing jurisdiction over various aspects of the exploration for, and the production and transportation of, natural gas. Failure to comply with such laws and regulations, including any evolving interpretation and enforcement by governmental authorities, could have a material adverse effect on our business, financial condition and results of operations.

Changes to existing or new regulations may unfavorably impact us, could result in increased operating costs and have a material adverse effect on our financial condition and results of operations. For example, Congress is currently considering legislation that, if adopted in its proposed form, would subject companies involved in natural gas and oil exploration and production activities to, among other items, additional regulation of and restrictions on hydraulic fracturing of wells, the elimination of certain U.S. federal tax incentives and deductions available to natural gas exploration and production companies, and the prohibition or additional regulation of private energy commodity derivative and hedging activities. These and other potential regulations could increase our operating costs, reduce our liquidity, delay or halt our operations or otherwise alter the way we conduct our business, which could in turn have a material adverse effect on our financial condition, results of operations and cash flows.

See "Business—Regulation of the Natural Gas and Oil Industry" for a further description of the laws and regulations that affect us.

Our operations may be exposed to significant delays, costs and liabilities as a result of environmental, health and safety requirements applicable to our business activities.

We may incur significant delays, costs and liabilities as a result of environmental, health and safety requirements applicable to our exploration, development and production activities. These delays, costs and liabilities could arise under a wide range of federal, state and local laws and regulations relating to protection of the environment, health and safety, including regulations and enforcement polices that have tended to become increasingly strict over time. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, imposition of cleanup and site restoration costs and liens, and, in some instances, issuance of orders or injunctions limiting or requiring discontinuation of certain operations. In addition, claims for damages to persons or property, including natural resources, may result from the environmental, health and safety impacts of our operations. Strict, joint and several liabilities may be imposed under certain environmental laws, which could cause us to become liable for the conduct of others or for consequences of our own actions that were in compliance with all applicable laws at the time those actions were taken.

New laws, regulations or enforcement policies could be more stringent and impose unforeseen liabilities or significantly increase compliance costs. If we were not able to recover the resulting costs through insurance or increased revenues, our business, financial condition or results of operations could be adversely affected.

See "Business—Regulation of Environmental and Occupational Matters" for a further description of the laws and regulations that affect us.

The unavailability or high cost of additional drilling rigs, equipment, supplies, personnel and oilfield services could adversely affect our ability to execute our exploration and development plans within our budget and on a timely basis.

The demand for qualified and experienced field personnel to drill wells and conduct field operations, geologists, geophysicists, engineers and other professionals in the natural gas and oil industry can fluctuate significantly, often in correlation with natural gas and oil prices, causing periodic shortages. Historically, there have been shortages of drilling and workover rigs, pipe and other equipment as demand for rigs and equipment has increased along with the number of wells being drilled. We cannot predict whether these conditions will exist in the future and, if so, what their timing and duration will be. Such shortages could delay or cause us to incur significant expenditures that are not provided for in our capital budget, which could have a material adverse effect on our business, financial condition or results of operations.

A change in the jurisdictional characterization of some of our assets by federal, state or local regulatory agencies or a change in policy by those agencies may result in increased regulation of our assets, which may cause our revenues to decline and operating expenses to increase.

Section 1(b) of the Natural Gas Act of 1938, or NGA, exempts natural gas gathering facilities from regulation by the Federal Energy Regulatory Commission, or FERC, as a natural gas company under the NGA. We believe that the natural gas pipelines in our gathering systems meet the traditional tests FERC has used to establish a pipeline's status as a gatherer not subject to regulation as a natural gas company. However, the distinction between FERC-regulated transmission services and federally unregulated gathering services is the subject of on-going litigation, so the classification and regulation of our gathering facilities are subject to change based on future determinations by FERC, the courts or Congress.

Should we fail to comply with all applicable FERC administered statutes, rules, regulations and orders, we could be subject to substantial penalties and fines.

Under the Domenici-Barton Energy Policy Act of 2005, FERC has civil penalty authority under the NGA to impose penalties for current violations of up to $1 million per day for each violation and disgorgement of profits associated with any violation. While our systems have not been regulated by FERC as a natural gas company under the NGA, FERC has adopted regulations that may subject certain of our otherwise non-FERC jurisdictional facilities to FERC annual reporting and daily scheduled flow and capacity posting requirements. Additional rules and legislation pertaining to those and other matters may be considered or adopted by FERC from time to time. Failure to comply with those regulations in the future could subject us to civil penalty liability.

The adoption of climate change legislation or regulations restricting emissions of "greenhouse gases" could result in increased operating costs and reduced demand for the natural gas we produce.

Recent scientific studies have suggested that emissions of certain gases, commonly referred to as "greenhouse gases" (GHGs) and including carbon dioxide and methane, may be contributing to warming of the Earth's atmosphere and other climatic changes. In response to such studies, the U.S. Congress is actively considering legislation to reduce emissions of GHGs. One bill approved by the U.S. House of Representatives in June 2009, known as the American Clean Energy and Security Act of 2009, or ACESA, would require an 80% reduction in emissions of GHGs from sources within the U.S. between 2012 and 2050. Similar bills are presently pending before the U.S. Senate. Moreover, almost half of the states have already taken legal measures to reduce emissions of GHGs, primarily through the planned development of GHG emission inventories and/or regional GHG cap and trade programs. Most of these cap and trade programs work by requiring major sources of emissions, such as electric power plants, or major producers of fuels, such as refineries and gas processing plants, to acquire and surrender emission allowances. The number of allowances available for purchase is reduced each year until the overall GHG emission reduction goal is achieved.

In addition, in December 2009, the U.S. Environmental Protection Agency, or the EPA, determined that emissions of carbon dioxide, methane and other GHGs present an endangerment to human health and the environment, because emissions of such gases are, according to the EPA, contributing to warming of the earth's atmosphere and other climatic changes. These findings by the EPA allow the agency to proceed with the adoption and implementation of regulations that would restrict emissions of GHGs under existing provisions of the federal Clean Air Act. In response to its endangerment finding, the EPA recently adopted two sets of rules regarding possible future regulation of GHG emissions under the Clean Air Act, one of which purports to regulate emissions of GHGs from motor vehicles and the other of which would regulate emissions of GHGs from large stationary sources of emissions such as power plants or industrial facilities. The motor vehicle rule became effective in March 2010 but it does not require immediate reductions in GHG emissions. The stationary source rule was adopted in May 2010 but it does not become effective until January 2011 and is the subject of several pending lawsuits filed by industry groups. Additionally, in September 2009, the EPA issued a final rule requiring the reporting of GHG emissions from specified large GHG emission sources in the U.S., including natural gas liquids fractionators and local natural gas/distribution companies, beginning in 2011 for emissions occurring in 2010.

The adoption of legislation or regulatory programs to reduce emissions of GHGs could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emissions allowances or comply with new regulatory requirements. Any such legislation or regulatory programs could also increase the cost of consuming, and thereby reduce demand for, the oil and natural gas we produced. Consequently, legislation and regulatory programs to reduce emissions of GHGs could have an adverse effect on our business, financial condition and results of operations.

The adoption of derivatives legislation by Congress could have an adverse impact on our ability to hedge risks associated with our business.

Congress currently is considering broad financial regulatory reform legislation that among other things would impose comprehensive regulation on the over-the-counter (OTC) derivatives marketplace and could affect the use of derivatives in hedging transactions. The financial regulatory reform bill adopted by the House of Representatives on December 11, 2009, would subject swap dealers and "major swap participants" to substantial supervision and regulation, including capital standards, margin requirements, business conduct standards, and recordkeeping and reporting requirements. It also would require central clearing for transactions entered into between swap dealers or major swap participants. For these purposes, a major swap participant generally would be someone other than a dealer who maintains a "substantial" net position in outstanding swaps, excluding swaps used for commercial hedging or for reducing or mitigating commercial risk, or whose positions create substantial net counterparty exposure that could have serious adverse effects on the financial stability of the U.S. banking system or financial markets. The House-passed bill also would provide the Commodity Futures Trading Commission (CFTC) with express authority to impose position limits for OTC derivatives related to energy commodities. Separately, in late January, 2010, the CFTC proposed regulations that would impose speculative position limits for certain futures and option contracts in natural gas, crude oil, heating oil, and gasoline. These proposed regulations would make an exemption available for certain *bona fide* hedging of commercial risks. On May 20, 2010, the Senate adopted its version of financial reform legislation. The Senate-passed bill would permit a "commercial end user" of certain derivatives to elect out of central clearing if it is using the derivative to hedge its own commercial risk, in which case new margin requirements also would not apply. House-Senate conferees must reconcile the two versions of the legislation, including the provisions applicable to derivatives, prior to final passage. Although it is not possible at this time to predict the final form the legislation will take, any laws or regulations that subject us to additional capital or margin requirements relating to, or to additional restrictions on, our trading and commodity positions could have an adverse effect on our ability to hedge risks associated with our business or on the cost of our hedging activity.

Federal and state legislation and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays.

Hydraulic fracturing is an important and common practice that is used to stimulate production of hydrocarbons, particularly natural gas, from tight formations. The process involves the injection of water, sand and chemicals under pressure into the formation to fracture the surrounding rock and stimulate production. The process is typically regulated by state oil and gas commissions but is not subject to regulation at the federal level. The EPA has commenced a study of the potential environmental impacts of hydraulic fracturing activities, and a committee of the U.S. House of Representatives is also conducting an investigation of hydraulic fracturing practices. Legislation has been introduced before Congress to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the fracturing process. In addition, some states are considering adopting regulations that could restrict hydraulic fracturing in certain circumstances. If new laws or regulations that significantly restrict hydraulic fracturing are adopted, such laws could make it more difficult or costly for us to perform fracturing to stimulate production from tight formations. In addition, if hydraulic fracturing is regulated at the federal level, our fracturing activities could become subject to additional permitting requirements, and also to attendant permitting delays and potential increases in costs. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that we are ultimately able to produce from our reserves.

Recent Colorado legislative changes could limit our Piceance Basin operations and adversely affect our cost of doing business.

Our future Piceance Basin operations and cost of doing business may be affected by changes in regulations and the ability to obtain drilling permits. Our properties located in the Piceance Basin are subject to the authority of the Colorado Oil and Gas Conservation Commission, or COGCC. The COGCC has the authority to regulate natural gas and oil activities to protect public health, safety and welfare, including the environment and wildlife. In 2007, the Colorado state legislature approved legislation requiring the COGCC to promulgate rules (1) in consultation with the Colorado Department of Public Health and Environment, or CDPHE, to provide CDPHE an opportunity to provide comments on public health issues during the COGCC's decision-making process and (2) in consultation with the Colorado Division of Wildlife, or CDOW, to establish standards for minimizing adverse impacts to wildlife resources affected by natural gas and oil operations and to ensure the proper reclamation of wildlife habitat during and following such operations. These rules became effective April 1, 2009 for the majority of our Piceance Basin operations. We believe the revised rules will cause additional costs and may cause delay in our operations in Colorado. The rules require consultation with the CDOW and CDPHE prior to drilling and completion operations in our Piceance Basin project area. These rules are open-ended and resulting permit restrictions remain subject to appeal by the CDOW, CDPHE and the surface owner. The rules also would impact the ability and extend the time necessary to obtain drilling permits, which creates substantial uncertainty about our ability to obtain sufficient permits in a timely fashion in order to meet future drilling plans and thus production and capital expenditure targets. It is also possible that similar rules will be proposed in the other states in which we operate, further impacting our operations.

Competition in the natural gas industry is intense, making it more difficult for us to acquire properties, market natural gas and secure trained personnel.

Our ability to acquire additional prospects and to find and develop reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment for acquiring properties, marketing natural gas and securing trained personnel. Also, there is substantial competition for capital available for investment in the oil and natural gas industry. Many of our competitors possess and employ financial, technical and personnel resources substantially greater than ours. Those companies may be able to pay more for productive natural gas properties and exploratory prospects and to evaluate, bid for and purchase a greater number of properties and prospects than our financial or personnel resources permit. In addition, other companies may be able to offer better compensation packages to attract and retain qualified personnel than we are able to offer. The cost to attract and retain qualified personnel has increased over the past three years due to competition and may increase substantially in the future. We may not be able to compete successfully in the future in acquiring prospective reserves, developing reserves, marketing hydrocarbons, attracting and retaining quality personnel and raising additional capital, which could have a material adverse effect on our business.

The loss of senior management or technical personnel could adversely affect operations.

We depend on the services of our senior management and technical personnel. The loss of the services of our senior management or technical personnel, including Paul M. Rady, our Chairman and Chief Executive Officer, and Glen C. Warren, Jr., our President and Chief Financial Officer, could have a material adverse effect on our operations. We do not maintain, nor do we plan to obtain, any insurance against the loss of any of these individuals.

We have limited control over activities on properties we do not operate, which could reduce our production and revenues.

A significant portion of our business activities is conducted through joint operating agreements under which we own partial interests in natural gas properties. If we do not operate the properties in which we own an interest, we do not have control over normal operating procedures, expenditures or future development of the underlying properties. The failure of an operator of our wells to adequately perform operations or an operator's breach of the applicable agreements could reduce our production and revenues. The success and timing of our drilling and development activities on properties operated by others, therefore, depends upon a number of factors outside of our control, including the operator's timing and amount of capital expenditures, expertise and financial resources, inclusion of other participants in drilling wells and use of technology. Because we do not have a majority interest in most wells that we do not operate, we may not be in a position to remove the operator in the event of poor performance.

Seasonal weather conditions and lease stipulations adversely affect our ability to conduct drilling activities in some of the areas where we operate.

Natural gas operations in our operating areas can be adversely affected by seasonal weather conditions and lease stipulations designed to protect various wildlife. In certain areas of Colorado, for example, drilling and other natural gas activities can only be conducted during the spring and summer months. This limits our ability to operate in those areas and can intensify competition during those months for drilling rigs, oilfield equipment, services, supplies and qualified personnel, which may lead to periodic shortages. These constraints and the resulting shortages or high costs could delay our operations and materially increase our operating and capital costs.

We have been an early entrant into new or emerging plays. As a result, our drilling results in these areas are uncertain, and the value of our undeveloped acreage will decline if drilling results are unsuccessful.

While our costs to acquire undeveloped acreage in new or emerging plays have generally been less than those of later entrants into a developing play, our drilling results in these areas are more uncertain than drilling results in areas that are developed and producing. Since new or emerging plays have limited or no production history, we are unable to use past drilling results in those areas to help predict our future drilling results. As a result, our cost of drilling, completing and operating wells in these areas may be higher than initially expected, and the value of our undeveloped acreage will decline if drilling results are unsuccessful.

Increases in interest rates could adversely affect our business.

Our business and operating results can be harmed by factors such as the availability, terms of and cost of capital, increases in interest rates or a reduction in credit rating. These changes could cause our cost of doing business to increase, limit our ability to pursue acquisition opportunities, reduce cash flow used for drilling and place us at a competitive disadvantage. For example, as of December 31, 2009, outstanding borrowings under our senior secured revolving credit facility were approximately $142 million, and the impact of a 1.0% increase in interest rates on this amount of indebtedness would result in increased annual interest expense of approximately $1.4 million and a corresponding decrease in our net income before the effects of increased interest rates on the value of our interest rate swap contracts. Recent and continuing disruptions and volatility in the global financial markets may lead to a contraction in credit availability impacting our ability to finance our operations. We require continued access to capital. A significant reduction in cash flows from operations or the availability of credit could materially and adversely affect our ability to achieve our planned growth and operating results.

We may be subject to risks in connection with acquisitions of properties.

The successful acquisition of producing properties requires an assessment of several factors, including:

- recoverable reserves;
- future natural gas prices and their applicable differentials;
- operating costs; and
- potential environmental and other liabilities.

The accuracy of these assessments is inherently uncertain. In connection with these assessments, we perform a review of the subject properties that we believe to be generally consistent with industry practices. Our review will not reveal all existing or potential problems nor will it permit us to become sufficiently familiar with the properties to fully assess their deficiencies and capabilities. Inspections may not always be performed on every well, and environmental problems are not necessarily observable even when an inspection is undertaken. Even when problems are identified, the seller may be unwilling or unable to provide effective contractual protection against all or part of the problems. We often are not entitled to contractual indemnification for environmental liabilities and acquire properties on an "as is" basis.

We may be unable to make attractive acquisitions or successfully integrate acquired businesses, and any inability to do so may disrupt our business and hinder our ability to grow.

In the future we may make acquisitions of businesses that complement or expand our current business. We may not be able to identify attractive acquisition opportunities. Even if we do identify attractive acquisition opportunities, we may not be able to complete the acquisition or do so on commercially acceptable terms.

The success of any completed acquisition will depend on our ability to integrate effectively the acquired business into our existing operations. The process of integrating acquired businesses may involve unforeseen difficulties and may require a disproportionate amount of our managerial and financial resources. In addition, possible future acquisitions may be larger and for purchase prices significantly higher than those paid for earlier acquisitions. No assurance can be given that we will be able to identify additional suitable acquisition opportunities, negotiate acceptable terms, obtain financing for acquisitions on acceptable terms or successfully acquire identified targets. Our failure to achieve consolidation savings, to incorporate the acquired businesses and assets into our existing operations successfully or to minimize any unforeseen operational difficulties could have a material adverse effect on our financial condition and results of operations.

In addition, our senior secured revolving credit facility imposes and the indenture governing the notes will impose certain limitations on our ability to enter into mergers or combination transactions. Our senior secured revolving credit facility and the indenture governing the notes also limit our ability to incur certain indebtedness, which could indirectly limit our ability to engage in acquisitions of businesses.

The obligations associated with being an SEC reporting company will require significant resources and management attention, which could have a material adverse effect on our business and operating results.

Following the effectiveness of the registration statement of which this prospectus forms a part, we will become subject to certain of the reporting requirements of the Exchange Act and the Sarbanes-Oxley Act of 2002, or the Sarbanes-Oxley Act. Under the Exchange Act, we will be required to file annual, quarterly and current reports with respect to our business and financial condition. Under the Sarbanes-Oxley Act, we will be required to, among other things, establish and maintain effective internal controls and procedures for financial reporting. As a result, we may incur significant additional legal, accounting and other expenses that we have not previously incurred. We anticipate that we may need to upgrade our systems, implement additional financial and management controls, reporting systems and procedures, implement an internal audit function, and hire additional accounting and internal audit staff. Furthermore, the need to establish the corporate infrastructure demanded of a reporting company may divert management's attention from implementing our growth strategy, which could prevent us from improving our business, results of operations and financial condition. We have made, and will continue to make, changes to our internal controls and procedures for financial reporting and accounting systems to meet our reporting obligations as a stand-alone public company. However, the measures we take may not be sufficient to satisfy our obligations as a public company. In addition, we cannot predict or estimate the amount of additional costs we may incur in order to comply with these requirements. We anticipate that these costs will materially increase our general and administrative expenses.

Section 404 of the Sarbanes-Oxley Act requires annual management assessments of the effectiveness of our internal control over financial reporting, starting with the annual report that we would expect to file with the SEC for the year ending December 31, 2011, and will require in such annual report, a report by our independent registered public accounting firm on the effectiveness of our internal control over financial reporting. In connection with the implementation of the necessary procedures and practices related to internal control over financial reporting, we may identify additional deficiencies. We may not be able to remediate any future deficiencies in time to meet the deadline imposed by the Sarbanes-Oxley Act for compliance with the requirements of Section 404. In addition, failure to achieve and maintain an effective internal control environment could have a material adverse effect on our business.

Risks Relating to Taxes

We may incur more taxes and certain of our projects may become uneconomic if certain federal income tax deductions currently available with respect to natural gas and oil exploration and development are eliminated as a result of future legislation.

President Obama's proposed budget for fiscal year 2010 contains a proposal to eliminate certain key U.S. federal income tax preferences currently available to natural gas and oil exploration and production companies. These changes include, but are not limited to (i) the repeal of the percentage depletion allowance for natural gas and oil properties, (ii) the elimination of current deductions for intangible drilling and development costs, (iii) the elimination of the deduction for certain U.S. production activities, and (iv) an extension of the amortization period for certain geological and geophysical expenditures. The Oil Industry Tax Break Repeal Act of 2009, which was introduced in the Senate on April 23, 2009, includes many of the same proposals.

It is unclear whether any of the foregoing changes will actually be enacted or how soon any such changes could become effective. The passage of any legislation as a result of the budget proposal, the Senate bill or any other similar change in U.S. federal income tax law could eliminate certain tax deductions that are currently available with respect to natural gas and oil exploration and development. Any such change could negatively impact our financial condition and results of operations by increasing the costs we incur which would in turn make it uneconomic to drill some prospects if commodity prices are not sufficiently high, resulting in lower revenues and decreases in production and reserves.

Recently proposed severance taxes in Pennsylvania could materially increase our liabilities.

A portion of our acreage in the Marcellus Shale in the Appalachian Basin is located in the State of Pennsylvania. Pennsylvania has historically not imposed a production or severance tax with respect to the production and sale of oil, natural gas and natural gas liquids within its jurisdiction. However, as a result of a focus on the state budget deficit and the increasing exploitation of the Marcellus Shale, the Pennsylvania state legislature is currently considering a proposed severance tax on natural gas drilling. If such legislation is adopted, these taxes may materially increase our operating costs in Pennsylvania.

EXCHANGE OFFER

Purpose and Effect of the Exchange Offer

At each closing of the offerings of the old notes, we entered into a registration rights agreement with the initial purchasers pursuant to which we agreed, for the benefit of the holders of the old notes, at our cost, to do the following:

- file an exchange offer registration statement with the SEC with respect to the exchange offer for the new notes, and
- use commercially reasonable efforts to have the exchange offer completed by the 360th day following the date of the initial issuance of the notes (November 17, 2009).

Upon the SEC's declaring the exchange offer registration statement effective, we agreed to offer the new notes in exchange for surrender of the old notes. We agreed to use commercially reasonable efforts to cause the exchange offer registration statement to be effective continuously, and to keep the exchange offer open for a period of not less than 20 business days.

For each old note surrendered to us pursuant to the exchange offer, the holder of such old note will receive a new note having a principal amount equal to that of the surrendered old note. Interest on each new note will accrue from the last interest payment date on which interest was paid on the surrendered old note or, if no interest has been paid on such old note, from November 17, 2009. The registration rights agreements also contain agreements to include in the prospectus for the exchange offer certain information necessary to allow a broker-dealer who holds old notes that were acquired for its own account as a result of market-making activities or other ordinary course trading activities (other than old notes acquired directly from us or one of our affiliates) to exchange such old notes pursuant to the exchange offer and to satisfy the prospectus delivery requirements in connection with resales of new notes received by such broker-dealer in the exchange offer. We agreed to use commercially reasonable efforts to maintain the effectiveness of the exchange offer registration statement for these purposes for a period of 180 days after the completion of the exchange offer, which period may be extended under certain circumstances.

The preceding agreement is needed because any broker-dealer who acquires old notes for its own account as a result of market-making activities or other trading activities is required to deliver a prospectus meeting the requirements of the Securities Act. This prospectus covers the offer and sale of the new notes pursuant to the exchange offer and the resale of new notes received in the exchange offer by any broker-dealer who held old notes acquired for its own account as a result of market-making activities or other trading activities other than old notes acquired directly from us or one of our affiliates.

Based on interpretations by the staff of the SEC set forth in no-action letters issued to third parties, we believe that the new notes issued pursuant to the exchange offer would in general be freely tradable after the exchange offer without further registration under the Securities Act. However, any purchaser of old notes who is an "affiliate" of ours or who intends to participate in the exchange offer for the purpose of distributing the related new notes:

- will not be able to rely on the interpretation of the staff of the SEC,
- will not be able to tender its new notes in the exchange offer, and
- must comply with the registration and prospectus delivery requirements of the Securities Act in connection with any sale or transfer of the old notes unless such sale or transfer is made pursuant to an exemption from such requirements.

Each holder of the old notes (other than certain specified holders) who desires to exchange old notes for the new notes in the exchange offer will be required to make the representations described below under "—Procedures for Tendering—Your Representations to Us."

We further agreed to file with the SEC a shelf registration statement to register for public resale of old notes held by any holder who provides us with certain information for inclusion in the shelf registration statement if:

- the exchange offer is not permitted by applicable law or SEC policy, or
- the exchange offer is not for any reason completed by the 360th day following the date of the initial issuance of the notes (November 17, 2009), or
- upon completion of the exchange offer, any initial purchaser shall so request in connection with any offering or sale of notes.

We have agreed to use commercially reasonable efforts to keep the shelf registration statement continuously effective until the earlier of one year following its effective date and such time as all notes covered by the shelf registration statement have been sold. We refer to this period as the "shelf effectiveness period."

The registration rights agreements provide that, in the event that either the exchange offer is not completed or the shelf registration statement, if required, is not declared effective (or does not automatically become effective) on or prior to the 360th calendar day following the date of the initial issuance of the notes (November 17, 2009), the interest rate on the old notes will be increased by 1.00% per annum until the exchange offer is completed or the shelf registration statement is declared effective (or automatically becomes effective) under the Securities Act, at which time the increased interest shall cease to accrue.

If the shelf registration statement has been declared effective (or automatically becomes effective) and thereafter either ceases to be effective or the prospectus contained therein ceases to be usable for resales of the notes at any time during the shelf effectiveness period, and such failure to remain effective or usable for resales of the notes exists for more than 30 calendar days (whether or not consecutive) in any 12-month period, then the interest rate on the old notes will be increased by 1.00% per annum commencing on the 31st day in such 12-month period and ending on such date that the shelf registration statement has again been declared (or automatically becomes) effective or the prospectus again becomes usable, at which time the increased interest shall cease to accrue.

Holders of the old notes will be required to make certain representations to us (as described in the registration rights agreements) in order to participate in the exchange offer and will be required to deliver information to be used in connection with the shelf registration statement and to provide comments on the shelf registration statement within the time periods set forth in the registration rights agreements in order to have their old notes included in the shelf registration statement.

If we effect the registered exchange offer, we will be entitled to close the registered exchange offer 20 business days after its commencement as long as we have accepted all old notes validly rendered in accordance with the terms of the exchange offer and no brokers or dealers continue to hold any old notes.

This summary of the material provisions of the registration rights agreements do not purport to be complete and is subject to, and is qualified in its entirety by reference to, all the provisions of the registration rights agreements, copies of which are filed as exhibits to the registration statement which includes this prospectus.

Except as set forth above, after consummation of the exchange offer, holders of old notes which are the subject of the exchange offer have no registration or exchange rights under the registration rights agreements. See "—Consequences of Failure to Exchange."

Terms of the Exchange Offer

Subject to the terms and conditions described in this prospectus and in the letter of transmittal, we will accept for exchange any old notes properly tendered and not withdrawn prior to 5:00 p.m. New York City time on the expiration date. We will issue new notes in principal amount equal to the principal amount of old notes surrendered in the exchange offer. Old notes may be tendered only for new notes and only in minimum denominations of $2,000 and integral multiples of $1,000 in excess thereof.

The exchange offer is not conditioned upon any minimum aggregate principal amount of old notes being tendered for exchange.

As of the date of this prospectus, $525,000,000 in aggregate principal amount of the old notes is outstanding. This prospectus and the letter of transmittal are being sent to all registered holders of old notes. There will be no fixed record date for determining registered holders of old notes entitled to participate in the exchange offer.

We intend to conduct the exchange offer in accordance with the provisions of the registration rights agreements, the applicable requirements of the Securities Act and the Exchange Act and the rules and regulations of the SEC. Old notes that the holders thereof do not tender for exchange in the exchange offer will remain outstanding and continue to accrue interest. These old notes will continue to be entitled to the rights and benefits such holders have under the indenture relating to the notes.

We will be deemed to have accepted for exchange properly tendered old notes when we have given oral or written notice of the acceptance to the exchange agent and complied with the applicable provisions of the registration rights agreements. The exchange agent will act as agent for the tendering holders for the purposes of receiving the new notes from us.

If you tender old notes in the exchange offer, you will not be required to pay brokerage commissions or fees or, subject to the letter of transmittal, transfer taxes with respect to the exchange of old notes. We will pay all charges and expenses, other than certain applicable taxes described below, in connecting with the exchange offer. It is important that you read the section labeled "—Fees and Expenses" for more details regarding fees and expenses incurred in the exchange offer.

We will return any old notes that we do not accept for exchange for any reason without expense to their tendering holder promptly after the expiration or termination of the exchange offer.

Expiration Date

The exchange offer will expire at 5:00 p.m., New York City time, on July 14, 2010, unless, in our sole discretion, we extend it.

Extensions, Delays in Acceptance, Termination or Amendment

We expressly reserve the right, at any time or various times, to extend the period of time during which the exchange offer is open. We may delay acceptance of any old notes by giving oral or written notice of such extension to their holders. During any such extensions, all old notes previously tendered will remain subject to the exchange offer, and we may accept them for exchange.

In order to extend the exchange offer, we will notify the exchange agent orally or in writing of any extension. We will notify the registered holders of old notes of the extension no later than 9:00 a.m., New York City time, on the first business day following the previously scheduled expiration date.

If any of the conditions described below under "—Conditions to the Exchange Offer" have not been satisfied, we reserve the right, in our sole discretion:

- to extend the exchange offer, or
- to terminate the exchange offer,

by giving oral or written notice of such delay, extension or termination to the exchange agent. Subject to the terms of the registration rights agreements, we also reserve the right to amend the terms of the exchange offer in any manner.

Any extension, termination or amendment will be followed promptly by oral or written notice thereof to the registered holders of old notes. If we amend the exchange offer in a manner that we determine to constitute a material change, we will promptly disclose such amendment by means of a prospectus supplement. The supplement will be distributed to the registered holders of the old notes. Depending upon the significance of the amendment and the manner of disclosure to the registered holders, we may extend the exchange offer. In the event of a material change in the exchange offer, including the waiver by us of a material condition, we will extend the exchange offer period if necessary so that at least five business days remain in the exchange offer following notice of the material change.

Conditions to the Exchange Offer

We will not be required to accept for exchange, or exchange any new notes for, any old notes if the exchange offer, or the making of any exchange by a holder of old notes, would violate applicable law or any applicable interpretation of the staff of the SEC. Similarly, we may terminate the exchange offer as provided in this prospectus before accepting old notes for exchange in the event of such a potential violation.

In addition, we will not be obligated to accept for exchange the old notes of any holder that has not made to us the representations described under "—Purpose and Effect of the Exchange Offer," "—Procedures for Tendering" and "Plan of Distribution" and such other representations as may be reasonably necessary under applicable SEC rules, regulations or interpretations to allow us to use an appropriate form to register the new notes under the Securities Act.

We expressly reserve the right to amend or terminate the exchange offer, and to reject for exchange any old notes not previously accepted for exchange, upon the occurrence of any of the conditions to the exchange offer specified above. We will give prompt oral or written notice of any extension, amendment, non-acceptance or termination to the holders of the old notes as promptly as practicable.

These conditions are for our sole benefit, and we may assert them or waive them in whole or in part at any time or at various times in our sole discretion. If we fail at any time to exercise any of these rights, this failure will not mean that we have waived our rights. Each such right will be deemed an ongoing right that we may assert at any time or at various times.

In addition, we will not accept for exchange any old notes tendered, and will not issue new notes in exchange for any such old notes, if at such time any stop order has been threatened or is in effect with respect to the registration statement of which this prospectus constitutes a part or the qualification of the indenture relating to the notes under the Trust Indenture Act of 1939.

Procedures for Tendering

In order to participate in the exchange offer, you must properly tender your old notes to the exchange agent as described below. It is your responsibility to properly tender your notes. We have the right to waive any defects. However, we are not required to waive defects and are not required to notify you of defects in your tender.

If you have any questions or need help in exchanging your notes, please call the exchange agent, whose contact information is set forth in "Prospectus Summary—The Exchange Offer—Exchange Agent."

All of the old notes were issued in book-entry form, and all of the old notes are currently represented by global certificates held for the account of DTC. We have confirmed with DTC that the old notes may be tendered using the Automated Tender Offer Program ("ATOP") instituted by DTC. The exchange agent will establish an account with DTC for purposes of the exchange offer promptly after the commencement of the exchange offer and DTC participants may electronically transmit their acceptance of the exchange offer by causing DTC to transfer their old notes to the exchange agent using the ATOP procedures. In connection with the transfer, DTC will send an "agent's message" to the exchange agent. The agent's message will state that DTC has received instructions from the participant to tender old notes and that the participant agrees to be bound by the terms of the letter of transmittal.

By using the ATOP procedures to exchange old notes, you will not be required to deliver a letter of transmittal to the exchange agent. However, you will be bound by its terms just as if you had signed it.

There is no procedure for guaranteed late delivery of the notes.

Determinations Under the Exchange Offer

We will determine in our sole discretion all questions as to the validity, form, eligibility, time of receipt, acceptance of tendered old notes and withdrawal of tendered old notes. Our determination will be final and binding. We reserve the absolute right to reject any old notes not properly tendered or any old notes our acceptance of which would, in the opinion of our counsel, be unlawful. We also reserve the right to waive any defect, irregularities or conditions of tender as to particular old notes. Our interpretation of the terms and conditions of the exchange offer, including the instructions in the letter of transmittal, will be final and binding on all parties. Unless waived, all defects or irregularities in connection with tenders of old notes must be cured within such time as we shall determine. Although we intend to notify holders of defects or irregularities with respect to tenders of old notes, neither we, the exchange agent nor any other person will incur any liability for failure to give such notification. Tenders of old notes will not be deemed made until such defects or irregularities have been cured or waived. Any old notes received by the exchange agent that are not properly tendered and as to which the defects or irregularities have not been cured or waived will be returned to the tendering holder, unless otherwise provided in the letter of transmittal, promptly following the expiration date.

When We Will Issue New Notes

In all cases, we will issue new notes for old notes that we have accepted for exchange under the exchange offer only after the exchange agent timely receives:

- a book-entry confirmation of such old notes into the exchange agent's account at DTC; and
- a properly transmitted agent's message.

Return of Old Notes Not Accepted or Exchanged

If we do not accept any tendered old notes for exchange or if old notes are submitted for a greater principal amount than the holder desires to exchange, the unaccepted or non-exchanged old notes will be returned without expense to their tendering holder. Such non-exchanged old notes will be credited to an account maintained with DTC. These actions will occur promptly after the expiration or termination of the exchange offer.

Your Representations to Us

By agreeing to be bound by the letter of transmittal, you will represent to us that, among other things:

- any new notes that you receive will be acquired in the ordinary course of your business;
- you have no arrangement or understanding with any person or entity to participate in the distribution of the new notes;
- you are not our "affiliate," as defined in Rule 405 of the Securities Act; and
- if you are a broker-dealer that will receive new notes for your own account in exchange for old notes, you acquired those notes as a result of market-making activities or other trading activities and you will deliver a prospectus (or to the extent permitted by law, make available a prospectus) in connection with any resale of such new notes.

Withdrawal of Tenders

Except as otherwise provided in this prospectus, you may withdraw your tender at any time prior to 5:00 p.m. New York City time on the expiration date. For a withdrawal to be effective you must comply with the appropriate procedures of DTC's ATOP system. Any notice of withdrawal must specify the name and number of the account at DTC to be credited with withdrawn old notes and otherwise comply with the procedures of DTC.

We will determine all questions as to the validity, form, eligibility and time of receipt of notice of withdrawal. Our determination shall be final and binding on all parties. We will deem any old notes so withdrawn not to have been validly tendered for exchange for purposes of the exchange offer.

Any old notes that have been tendered for exchange but are not exchanged for any reason will be credited to an account maintained with DTC for the old notes. This crediting will take place as soon as practicable after withdrawal, rejection of tender or termination of the exchange offer. You may retender properly withdrawn old notes by following the procedures described under "—Procedures for Tendering" above at any time prior to 5:00 p.m., New York City time, on the expiration date.

Fees and Expenses

We will bear the expenses of soliciting tenders. The principal solicitation is being made by mail; however, we may make additional solicitation by facsimile, telephone, electronic mail or in person by our officers and regular employees and those of our affiliates.

We have not retained any dealer-manager in connection with the exchange offer and will not make any payments to broker-dealers or others soliciting acceptances of the exchange offer. We will, however, pay the exchange agent reasonable and customary fees for its services and reimburse it for its related reasonable out-of-pocket expenses.

We will pay the cash expenses to be incurred in connection with the exchange offer. They include:

- all registration and filing fees and expenses;
- all fees and expenses of compliance with federal securities and state "blue sky" or securities laws;
- accounting fees, legal fees incurred by us, disbursements and printing, messenger and delivery services, and telephone costs; and
- related fees and expenses.

Transfer Taxes

We will pay all transfer taxes, if any, applicable to the exchange of old notes under the exchange offer. The tendering holder, however, will be required to pay any transfer taxes, whether imposed on the registered holder or any other person, if a transfer tax is imposed for any reason other than the exchange of old notes under the exchange offer.

Consequences of Failure to Exchange

If you do not exchange new notes for your old notes under the exchange offer, you will remain subject to the existing restrictions on transfer of the old notes. In general, you may not offer or sell the old notes unless the offer or sale is either registered under the Securities Act or exempt from the registration under the Securities Act and applicable state securities laws. Except as required by the registration rights agreements, we do not intend to register resales of the old notes under the Securities Act.

Accounting Treatment

We will record the new notes in our accounting records at the same carrying value as the old notes. This carrying value is the aggregate principal amount of the old notes adjusted for any bond discount or premium, as reflected in our accounting records on the date of exchange. Accordingly, we will not recognize any gain or loss for accounting purposes in connection with the exchange offer.

Other

Participation in the exchange offer is voluntary, and you should carefully consider whether to accept. You are urged to consult your financial and tax advisors in making your own decision on what action to take.

We may in the future seek to acquire untendered old notes in open market or privately negotiated transactions, through subsequent exchange offers or otherwise. We have no present plans to acquire any old notes that are not tendered in the exchange offer or to file a registration statement to permit resales of any untendered old notes.

USE OF PROCEEDS

The exchange offer is intended to satisfy our obligations under the registration rights agreements. We will not receive any proceeds from the issuance of the new notes in the exchange offer. In consideration for issuing the new notes as contemplated by this prospectus, we will receive old notes in a like principal amount. The form and terms of the new notes are identical in all respects to the form and terms of the old notes, except the new notes will be registered under the Securities Act and will not contain restrictions on transfer, registration rights or provisions for additional interest. Old notes surrendered in exchange for the new notes will be retired and cancelled and will not be reissued. Accordingly, the issuance of the new notes will not result in any change in our outstanding indebtedness.

SELECTED HISTORICAL CONSOLIDATED FINANCIAL DATA

The following table shows our selected historical consolidated financial data, for the periods and as of the dates indicated, for Antero Resources LLC and its subsidiaries. The subsidiaries of Antero Resources LLC include Antero Resources Corporation, Antero Resources Midstream Corporation, Antero Resources Piceance Corporation, Antero Resources Pipeline Corporation, Antero Resources Appalachian Corporation (collectively referred to as the "Antero Entities" or the "operating entities"), and Antero Finance Corporation. Prior to the formation of Antero Resources LLC in 2009, the Antero Entities were under common control, as the ownership interests in each entity were held by the same individual stockholders in the same percentages. In 2009, the ownership interests in each of the Antero Entities were contributed to a newly formed limited liability company, Antero Resources LLC, resulting in each entity being a wholly owned subsidiary of Antero Resources LLC. The assets and liabilities of the Antero Entities were carried forward at their historical basis. The selected statement of operations data for the year ended December 31, 2007, 2008 and 2009 and the balance sheet data as of December 31, 2008 and 2009 are derived from our audited consolidated financial statements included elsewhere in this prospectus. The selected statement of operations data for the years ended December 31, 2005 and 2006 and the balance sheet data as of December 31, 2005, 2006 and 2007 are derived from our audited combined financial statements not included in this prospectus. The selected statement of operations data for the three months ended March 31, 2009 and 2010 and balance sheet data as of March 31, 2010 are derived from our unaudited consolidated financial statements included elsewhere in this prospectus. The selected balance sheet data as of March 31, 2009 has been derived from our unaudited and unreviewed consolidated financial statements not included in this prospectus. The selected unaudited consolidated financial data has been prepared on a consistent basis with our audited consolidated financial statements. In the opinion of management, such selected unaudited consolidated financial data reflects all adjustments (consisting of normal and recurring accruals) considered necessary to present our financial position for the periods presented. The results of operations for the interim periods are not necessarily indicative of the results that may be expected for the full year because of the impact of fluctuations in prices received from natural gas and oil, natural production declines, the uncertainty of exploration and development drilling results and other factors. The selected financial data presented below are qualified in their entirety by reference to, and should be read in conjunction with, "Management's Discussion and Analysis of Financial Condition and

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Results of Operations" and our consolidated financial statements and related notes included elsewhere in this prospectus.

(in thousands, except ratios)	Year Ended December 31, 2005	2006	2007	2008	2009	Three Months Ended March 31, 2009	2010
Statement of operations data:							
Operating revenues:							
Natural gas sales	$ 14,526	$ 14,271	$ 63,975	$ 220,219	$ 123,915	$ 37,332	$ 53,952
Oil sales	195	523	3,749	9,496	5,706	1,063	2,114
Realized and unrealized gains (losses) on commodity derivative instruments	(13,148)	14,331	18,992	116,354	55,364	38,686	111,083
Gathering and processing revenue	294	717	4,778	20,421	23,005	4,379	6,413
Total revenues	1,867	29,842	91,494	366,490	207,990	81,460	173,562
Operating expenses:							
Lease operating expenses	808	1,189	4,435	13,350	17,606	6,945	4,598
Gathering, compression and transportation	920	2,482	10,016	29,033	28,190	6,375	10,141
Production taxes	445	1,012	2,233	10,281	4,940	1,832	2,670
Exploration expense	5,455	8,832	17,970	22,998	10,228	2,429	1,352
Impairment of unproved properties	30,000	8,117	4,995	10,112	54,204	7,767	2,262
Depletion, depreciation and amortization	6,526	7,940	50,091	124,821	139,813	39,701	32,996
Accretion of asset retirement obligations	—	9	68	176	265	62	73
General and administrative	3,755	7,478	11,682	16,171	20,843	4,406	4,412
Total operating expenses	47,909	37,059	101,490	226,942	276,089	69,517	58,504
Operating income (loss)	(46,042)	(7,217)	(9,996)	139,548	(68,099)	11,943	115,058
Other income (expense):							
Interest expense	(592)	(1,366)	(25,124)	(37,594)	(36,053)	(7,178)	(13,292)
Realized and unrealized gains (losses) on interest derivative instruments, net	—	—	(3,033)	(15,245)	(4,985)	(1,375)	(1,602)
Total other expense	(592)	(1,366)	(28,157)	(52,839)	(41,038)	(8,553)	(14,894)
Income (loss) before income taxes	(46,634)	(8,583)	(38,153)	86,709	(109,137)	3,390	100,164
Income tax							

(expense) benefit	—	(400)	400	(3,029)	2,605	1,605	(11,318)
Net income (loss)	(46,634)	(8,983)	(37,753)	83,680	(106,532)	4,995	88,846
Noncontrolling interest in net loss of consolidated subsidiary	—	—	—	276	363	159	(1,241)
Net income (loss) attributable to Antero equity owners	$ (46,634)	$ (8,983)	$ (37,753)	$ 83,956	$ (106,169)	$ 5,154	$ 87,605

(in thousands, except ratios)	Year Ended December 31, 2005	2006	2007	2008	2009	Three Months Ended March 31, 2009	2010
Balance sheet data (at period end):							
Cash and cash equivalents	$ —	$ 1,945	$ 11,114	$ 38,969	$ 10,669	$ —	$ 6,314
Other current assets	57,502	35,036	64,145	165,199	84,175	152,020	125,943
Total current assets	57,502	36,981	75,259	204,168	94,844	152,020	132,257
Natural gas properties, at cost (successful efforts method):							
Unproved properties	41,186	61,307	201,210	649,605	596,694	645,033	600,233
Producing properties	15,841	208,127	617,697	1,148,306	1,340,827	1,205,485	1,407,126
Gathering systems and facilities	—	40,247	133,917	179,836	185,688	181,470	188,506
Other property and equipment	1,004	1,068	1,440	3,113	3,302	3,154	3,474
	58,031	310,749	954,264	1,980,860	2,126,511	2,035,142	2,199,339
Less accumulated depletion, depreciation, and amortization	(325)	(8,208)	(58,299)	(183,145)	(322,992)	(222,854)	(355,995)
Property and equipment, net	57,706	302,541	895,965	1,797,715	1,803,519	1,812,288	1,843,344
Other assets	207	920	8,058	27,084	38,203	29,630	100,297
Total assets	$ 115,415	$ 340,442	$ 979,282	$ 2,028,967	$ 1,936,566	$ 1,993,938	$ 2,075,898
Current liabilities	$ 25,346	$ 78,258	$ 165,091	$ 208,209	$ 112,493	$ 156,749	$ 138,612
Long-term indebtedness	13,500	83,897	415,659	622,734	515,499	532,702	529,304
Other long-term liabilities	113	859	4,230	20,469	9,467	15,629	20,029
Total equity	76,456	177,428	394,302	1,177,555	1,299,107	1,288,858	1,387,953
Total liabilities and equity	$ 115,415	$ 340,442	$ 979,282	$ 2,028,967	$ 1,936,566	$ 1,993,938	$ 2,075,898
Other financial data:							
EBITDAX(1)	$ 3,475	$ (629)	$ 59,980	$ 208,513	$ 201,270	$ 57,329	$ 51,725
Net cash provided by (used in) operating activities	(12,227)	(18,101)	24,745	157,515	$ 149,307	$ 66,640	51,989
Net cash used in investing	(41,523)	(158,265)	(600,902)	(1,004,010)	(281,899)	(115,321)	(65,989)
Net cash provided by financing activities	53,750	178,311	585,326	874,350	104,292	9,712	9,645
Capital expenditures(2)	61,425	367,019	646,469	1,041,748	203,454	65,939	75,390
Ratio of EBITDAX to interest expense	4.13x	—(3)	2.39x	5.55x	5.58x	7.99x	3.89x

(1) "EBITDAX" is a non-GAAP financial measure that we define as net income before interest expense, realized and unrealized gains or losses on interest rate derivative instruments, taxes, impairments, depletion, depreciation,

amortization, exploration expense, unrealized commodity hedge gains or losses, franchise taxes, stock compensation and interest income. "EBITDAX," as used and defined by us, may not be comparable to similarly titled measures employed by other companies and is not a measure of performance calculated in accordance with GAAP. EBITDAX should not be considered in isolation or as a substitute for operating income, net income or loss, cash flows provided by operating, investing and financing activities, or other income or cash flow statement data prepared in accordance with GAAP. EBITDAX provides no information regarding a company's capital structure, borrowings, interest costs, capital expenditures, and working capital movement or tax position. EBITDAX does not represent funds available for discretionary use because those funds are required for debt service, capital expenditures, working capital, income taxes, franchise taxes, exploration expenses, and other commitments and obligations. However, our management team believes EBITDAX is useful to an investor in evaluating our operating performance because this measure:

- is widely used by investors in the natural gas and oil industry to measure a company's operating performance without regard to items excluded from the calculation of such term, which can vary substantially from company to company depending upon accounting methods and book value of assets, capital structure and the method by which assets were acquired, among other factors;
- helps investors to more meaningfully evaluate and compare the results of our operations from period to period by removing the effect of our capital structure from our operating structure; and
- is used by our management team for various purposes, including as a measure of operating performance, in presentations to our board of directors, as a basis for strategic planning and forecasting and by our lenders pursuant to a covenant under our senior secured revolving credit facility. EBITDAX is also used as a measure of our operating performance pursuant to a covenant under the indenture governing the notes.

There are significant limitations to using EBITDAX as a measure of performance, including the inability to analyze the effect of certain recurring and non-recurring items that materially affect our net income or loss, the lack of comparability of results of operations of different companies and the different methods of calculating EBITDAX reported by different companies. The following table represents a reconciliation of our net income to EBITDAX for the periods presented:

	Year Ended December 31,					Three Months Ended March 31,	
(in thousands)	2005	2006	2007	2008	2009	2009	2010
Net income (loss)	$ (46,634)	$ (8,983)	$ (37,753)	$ 83,956	$ (106,169)	$ 5,154	$ 87,605
Unrealized (gains) losses on commodity derivative contracts	7,371	(18,656)	(4,619)	(90,301)	61,186	(5,114)	(98,812)
Interest expense and other	841	1,366	28,157	52,839	41,038	8,553	14,894
Provision (benefit) for income taxes	—	400	(400)	3,029	(2,605)	(1,605)	11,318
Depreciation, depletion, amortization and accretion	6,526	7,949	50,159	124,997	140,078	39,763	33,069
Impairment of unproved properties	30,000	8,117	4,995	10,112	54,204	7,767	2,262
Exploration expense	5,455	8,832	17,970	22,998	10,228	2,429	1,352
Other	(84)	346	1,471	883	3,310	382	37
EBITDAX	$ 3,475	$ (629)	$ 59,980	$ 208,513	$ 201,270	$ 57,329	$ 51,725

(2) Capital expenditures as shown in this table differ from the amounts shown in the statement of cash flows in the financial statements because amounts in this table include changes in accounts payable for capital expenditures from the previous reporting period while the amounts in the statement of cash flows in the financial statements are presented on a cash basis.

(3) Our EBITDAX was insufficient to cover our interest expense for this period by approximately $2.0 million.

RATIOS OF EARNINGS TO FIXED CHARGES

The following table sets forth our ratios of earnings to fixed charges for the periods presented:

	Year Ended December 31,						Three Months Ended March 31,
	2005	2006	2007	2008	2009	Pro forma 2009	2010
Ratio of earnings to fixed charges(1)	—(2)	—(2)	—(2)	3.30x	—(2)	—(1)	8.50x

(1) For purposes of computing the ratio of earnings to fixed charges, "earnings" consists of pretax income (loss) plus fixed charges. "Fixed charges" represents interest incurred, amortization of deferred debt offering costs and that portion of rental expense on operating leases deemed to be the equivalent of interest. Because the net proceeds of the November 2009 and January 2010 offerings of the old notes were used to repay indebtedness, pro forma impact on the amount of fixed charges causes our deficiency in earnings to cover fixed charges to change by 10% or more for the year ended December 31, 2009. Because the old notes and related interest were included in our financial results for most of the three months ended March 31, 2010, the pro forma impact on the amount of fixed charges did not cause our ratio of earnings to fixed charges to change by more than 10% for that period. After giving effect to the application of the net proceeds of the November 2009 and January 2010 offerings of the old notes, including the application of the net proceeds therefrom to repay borrowings under our senior secured revolving credit facility as if such transactions had occurred at the beginning of 2009 (which borrowings repaid under our senior secured revolving credit facility may be reborrowed from time to time, including for general corporate purposes and to fund our capital expenditure program), our pro forma earnings would have been inadequate to cover fixed charges for the year ended December 31, 2009 by approximately $129.3 million. This pro forma data does not give effect to the application of the net proceeds of our November 2009 $125 million equity placements. At December 31, 2009, we had approximately $142.1 million of borrowings outstanding under our senior secured revolving credit facility. The average interest rate paid on amounts outstanding under our senior secured revolving credit facility for the year ended December 31, 2009 was 4.2% (excluding the impact of our interest rate swaps).

(2) We generated operating losses for each of the years ended December 31, 2005, 2006, 2007 and 2009. Accordingly, our earnings were inadequate to cover total fixed charges during such periods by approximately $46.6 million, $8.6 million, $38.2 million and $109.1 million, respectively.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with our combined financial statements and related notes appearing elsewhere in this prospectus. The following discussion contains "forward-looking statements" that reflect our future plans, estimates, beliefs and expected performance. We caution that assumptions, expectations, projections, intentions, or beliefs about future events may, and often do, vary from actual results and the differences can be material. Some of the key factors which could cause actual results to vary from our expectations include changes in natural gas and oil prices, the timing of planned capital expenditures, availability of acquisitions, uncertainties in estimating proved reserves and forecasting production results, operational factors affecting the commencement or maintenance of producing wells, the condition of the capital markets generally, as well as our ability to access them and uncertainties regarding environmental regulations or litigation and other legal or regulatory developments affecting our business, as well as those factors discussed below and elsewhere in this prospectus, all of which are difficult to predict. In light of these risks, uncertainties and assumptions, the forward-looking events discussed may not occur. See "Cautionary Statement Regarding Forward-Looking Statements." In this section, references to "Antero," "we," "us," "our" and "operating entities" refer to the five corporations referred to as the operating entities in the other portions of this prospectus (Antero Resources Corporation, Antero Resources Midstream Corporation, Antero Resources Piceance Corporation, Antero Resources Pipeline Corporation and Antero Resources Appalachian Corporation), unless otherwise indicated or the context otherwise requires.

Overview

Antero Resources is an independent oil and natural gas company engaged in the exploration, development and production of natural gas properties located onshore in the United States. We focus on unconventional reservoirs, which can generally be characterized as fractured shales and tight sand formations. Our properties are primarily located in the Appalachian Basin in West Virginia and Pennsylvania, the Arkoma Basin in Oklahoma and the Piceance Basin in Colorado. Our corporate headquarters are in Denver, Colorado.

Our management team has worked together for many years and has a successful track record of reserve and production growth as well as significant expertise in unconventional resource plays. Our strategy is to leverage our team's experience delineating and developing natural gas resource plays to profitably grow our reserves and production, primarily through internally generated projects on our existing acreage. As of December 31, 2009, our estimated proved reserves were 1,140.7 Bcfe, consisting of 1,130.3 Bcf of natural gas and 1.7 MMBbl of oil and condensate. As of December 31, 2009, 99% of our proved reserves were natural gas, 24% were proved developed and 69% were operated by us. From December 31, 2006 through December 31, 2009, we grew our estimated proved reserves from 87.0 Bcfe to 1,140.7 Bcfe. In addition, we grew our average daily production from 30.8 MMcfe/d for the year ended December 31, 2007 to 105.2 MMcfe/d for the year ended December 31, 2009 and to 117.8 MMcfe/d for the three months ended March 31, 2010. For the years ended December 31, 2008 and 2009, we generated cash flow from operations of $157.5 million and $149.3 million, respectively, net income (loss) of $84.0 million and $(106.2) million, respectively, and EBITDAX of $208.5 million and $201.3 million, respectively. For the three months ended March 31, 2010, we generated cash flow from operations of $52.0 million, net income of $87.6 million and EBITDAX of $51.7 million. See "Selected Historical Combined Financial Data" for a definition of EBITDAX (a non-GAAP measure) and a reconciliation of EBITDAX to net income (loss).

We have assembled a diversified portfolio of long-lived properties that are characterized by what we believe to be low geologic risk and a large inventory of repeatable drilling opportunities. Our drilling opportunities are focused in the Marcellus Shale of the Appalachian Basin, the Woodford Shale of the Arkoma Basin (the Arkoma Woodford), the Fayetteville Shale of the Arkoma Basin and the Mesaverde tight sands and Mancos Shale of the Piceance Basin. From inception, we have drilled and operated 285 wells through December 31, 2009 with a success rate of approximately 98%. Our drilling inventory consists of approximately 16,000 potential locations, all of which are resource-style opportunities and approximately 9.8% of which are included in our estimated proved reserve base as of December 31, 2009. For information on the possible limitations on our ability to drill our potential locations, see "Risk Factors—Risks Relating to Our Business—Our identified drilling locations are scheduled out over many years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling. In addition, we may not be able to raise the substantial amount of capital that would be necessary to drill a substantial portion of our potential drilling locations."

We own two midstream systems in the Arkoma and Piceance Basins, and we believe we have secured sufficient long-term firm takeaway capacity on major pipelines that are in existence or currently under construction in each of our core operating areas to accommodate our existing and foreseeable production.

For the year ended December 31, 2009, we spent approximately $203.5 million on capital expenditures, approximately 89% of which is allocated to low-risk development projects with the remaining capital budget allocated to infrastructure projects and land acquisition. Our board of directors has approved a capital expenditure budget of up to $366 million for 2010, approximately 89% of which is allocated to drilling. Of our 2010 drilling budget, approximately 43% is allocated to the Appalachian Basin, 29% to the Arkoma Basin Woodford Shale and 28% to the Piceance Basin. Consistent with our historical practice, we periodically review our capital expenditures and adjust our budget based on liquidity, commodity prices and drilling results.

We believe we have a conservative financial position characterized by modest leverage, a strong hedge position and ample liquidity. We have entered into hedging contracts covering a total of approximately 173 Bcf of our natural gas production from April 1, 2010 through December 31, 2014 at a weighted average index price of $6.38 per Mcf. For the nine months ending December 31, 2010, we have hedged approximately 23.6 Bcf of our production at a weighted average index price of $6.13 per Mcf. On November 17, 2009, we completed an offering of $375 million principal amount of our 9.375% senior notes due 2017. On January 19, 2010, we completed an offering of $150 million additional principal amount of our 9.375% senior notes due 2017. On May 12, 2010, the borrowing base under our senior secured revolving credit facility was redetermined at $400 million (the maximum available under the facility). As of such date, after giving effect to the redetermination, we had approximately $361 million of available borrowing capacity under our senior secured revolving credit facility.

We operate in one industry segment, which is the exploration, development and production of natural gas and oil, and all of our operations are conducted in the United States. Our gathering and processing assets are primarily dedicated to supporting the natural gas volumes we produce.

Source of Our Revenues

Our production revenues are entirely from the continental United States and currently is comprised of 95% natural gas and 5% oil. Gas prices reached historically high levels in recent years and reached over $13.00 per Mcf in July 2008. Since then, natural gas prices have declined sharply to approximately $4.00 per Mcf in April 2010. Natural gas and oil prices are inherently volatile and are influenced by many factors outside of our control. To achieve more predictable cash flows and to reduce our exposure to downward price fluctuations, we use derivative instruments to hedge future sales prices on a significant portion of our natural gas production. We currently use fixed price natural gas swaps in which we receive a fixed price for future production in exchange for a payment of the variable market price received at the time future production is sold. For example, for the year ended December 31, 2009, we received approximately $116.5 million in cash flows pursuant to our hedges. At each period end we estimate the fair value of these swaps and recognize an unrealized gain or loss. We have not elected hedge accounting and, accordingly, the unrealized gains and losses on open positions are reflected currently in earnings. During the years ended December 31, 2007, 2008 and 2009, we recognized significant unrealized commodity gains on these swaps as market prices were lower than our fixed price swaps. We expect continued volatility in the fair value of these swaps. We do not enter into derivatives to manage volatility for our oil or NGL sales.

Principal Components of Our Cost Structure

- *Lease operating and gathering, compression and transportation expenses.* These are daily costs incurred to bring natural gas and oil out of the ground and to the market, together with the daily costs incurred to maintain our producing properties. Such costs also include maintenance, repairs and workover expenses related to our natural gas and oil properties. These costs stabilized in 2009 and are expected to remain moderate in the first half of 2010.

- *Production taxes.* Production taxes consist of severance and ad valorem taxes and are paid on produced natural gas and oil based on a percentage of market prices (not hedged prices) or at fixed rates established by federal, state or local taxing authorities.

- *Exploration expense.* These are geological and geophysical costs, including payroll and benefits for the geological and geophysical staff, seismic costs, delay rentals and the costs of unsuccessful exploratory dry holes and unsuccessful leasing efforts.

- *Impairment of unproved and proved properties.* These costs include unproved property impairment and costs associated with lease expirations. We could also record impairment charges for proved properties if the carrying value were to exceed estimated future cash flows. Through December 31, 2009, it has not been necessary to record any impairment for proved properties.

- *Depreciation, depletion and amortization.* This includes the systematic expensing of the capitalized costs incurred to acquire, explore and develop natural gas and oil. As a successful efforts company, we capitalize all costs associated with our acquisition and development efforts and all successful exploration efforts, and allocate these costs to each unit of production using the units of production method.

- *General and administrative expense.* These costs include overhead, including payroll and benefits for our corporate staff, costs of maintaining our headquarters, costs of managing our production and development operations, franchise taxes, audit and other professional fees and legal compliance are included in general and administrative expenses.

- *Interest expense.* We finance a portion of our working capital requirements and acquisitions with borrowings under our bank credit facilities. As a result, we incur substantial interest expense that is affected by both fluctuations in interest rates and our financing decisions. We also have fixed interest at 9.375% on the new notes having a principal balance of $525 million. We will likely continue to incur significant interest expense as we continue to grow. We have also entered into various variable to fixed interest rate swaps to mitigate the effects of interest rate changes. We do not designate these swaps as hedges and therefore do not accord them hedge accounting treatment. Realized and unrealized gains or losses on these interest rate derivative instruments are included as a separate line item in other income (expense).

- *Income tax expense.* Each of the operating entities files separate federal and state income tax returns; therefore, our provision for income taxes consists of the sum of our income tax provisions for each of the operating entities. We are subject to state and federal income taxes but are currently not in a tax paying position for regular federal income taxes, primarily due to the current deductibility of intangible drilling costs ("IDC"). We do pay some state income or franchise taxes where our IDC deductions do not exceed our taxable income or where state income or franchise taxes are determined on another basis. Collectively, the operating entities have generated net operating loss carryforwards which expire starting in 2024 through 2029. We have not recognized the full value of these net operating losses on our balance sheets because our management team believes it is more likely than not that we will not realize a future benefit equal to the full amount of the loss carryforward over time. The amount of deferred tax assets considered realizable, however, could change in the near term as we generate taxable income or estimates of future taxable income are reduced. We have recognized deferred tax expense for certain subsidiaries that have deferred tax liabilities in excess of their deferred tax assets due to unrealized gains on derivative instruments and basis differences in assets.

Significant Acquisitions

The following table presents a summary of our significant proved and unproved property acquisitions in 2007 and 2008. There were no significant acquisitions in 2009.

Primary locations of acquired properties	Date acquired	Purchase price (in millions)
Arkoma Basin Woodford Shale (OK)	December 2007	$ 61.0
Piceance Basin (CO)	July 2008	$ 39.2
Appalachian Basin (PA, WV)	September 2008	$ 347.0

Our acquisitions were financed with a combination of funding from equity contributions, borrowings under our credit facilities and cash flow from operations.

Results of Operations

Year Ended December 31, 2008 Compared to Year Ended December 31, 2009

The following table sets forth selected operating data for the year ended December 31, 2008 compared to the year ended December 31, 2009:

	Years Ended December 31,		Amount of	
(in thousands, except per unit data)	2008	2009	Increase (Decrease)	Percent Change
Operating revenues:				
Natural gas sales	$ 220,219	$ 123,915	$ (96,304)	(43.7)%
Oil sales	9,496	5,706	(3,790)	(39.9)%
Realized commodity derivative gains	26,053	116,550	90,497	347.3%
Unrealized commodity derivative gains (losses)	90,301	(61,186)	(151,487)	*
Gathering and processing	20,421	23,005	2,584	12.7%
Total operating revenues	366,490	207,990	(158,500)	(43.2)%
Operating expenses:				
Lease operating expense	13,350	17,606	4,256	31.9%
Gathering, compression and transportation	29,033	28,190	(843)	(2.9)%
Production taxes	10,281	4,940	(5,341)	(52.0)%
Exploration expense	22,998	10,228	(12,770)	(55.5)%
Impairment of unproved properties	10,112	54,204	44,092	436.0%
Depletion depreciation and amortization	124,821	139,813	14,992	12.0%
Accretion of asset retirement obligations	176	265	89	50.6%
General and administrative	16,171	20,843	4,672	28.9%
Total operating expenses	226,942	276,089	49,147	21.7%
Operating income (loss)	139,548	(68,099)	(207,647)	*

(in thousands, except per unit data)	Years Ended December 31, 2008	2009	Amount of Increase (Decrease)	Percent Change
Other income expense:				
Interest expense	$ (37,594)	$ (36,053)	$ (1,541)	(4.1)%
Relized and unrealized interest rate derivative gains (losses)	(15,245)	(4,985)	(10,260)	(67.3)%
Total other expense	(52,839)	(41,038)	(11,801)	(22.3)%
Income (loss) before income taxes	86,709	(109,137)	(195,846)	*
Provision for income taxes (expense) benefit	(3,029)	2,605	5,634	*
Net income (loss)	83,680	(106,532)	(190,012)	*
Non-controlling interest in net income of consolidated subsidiary	276	363	87	*
Net income (loss) attributable to Antero stockholders	$ 83,956	$ (106,169)	$ (190,125)	*
Production data:				
Natural gas (Bcf)	30.3	35.1	4.8	15.8%
Oil (MBbl)	114.9	114.0	(0.9)	(0.8)%
NGLs (Bcfe)(1)	0.9	2.6	1.7	188.9%
Combined (Bcfe)	31.9	38.4	6.5	20.4%
Daily combined production (MMcfe/d)	87.4	105.2	17.8	20.4%
Average prices before effects of hedges(2):				
Natural gas (per Mcf)	$ 7.27	$ 3.53	$ (3.74)	(51.4)%
Oil (per Bbl)	$ 82.65	$ 50.05	$ (32.60)	(39.4)%
Combined (per Mcfe)	$ 7.41	$ 3.62	$ (3.79)	(51.1)%
Average realized prices after effects of hedges(2):				
Natural gas (per Mcf)	$ 8.13	$ 6.85	$ (1.28)	(15.7)%
Oil (per Bbl)	$ 82.65	$ 50.05	$ (32.60)	(39.4)%
Combined (per Mcfe)	$ 8.25	$ 6.88	$ (1.37)	(16.6)%
Average Costs (per Mcfe):				
Lease operating costs	$ 0.43	$ 0.49	$ 0.06	14.0%
Gathering, compression and transportation	$ 0.94	$ 0.79	$ (0.15)	(16.0)%
Production taxes	$ 0.33	$ 0.14	$ (0.19)	(57.6)%
Depletion, depreciation amortization and accretion	$ 4.03	$ 3.91	$ (0.12)	(3.0)%
General and administrative	$ 0.52	$ 0.58	$ 0.06	11.5%

(1) Represents NGLs retained by our midstream business as compensation for processing third-party gas under long term contracts. These amounts are not reflected in the per Mcfe data in this table.

(2) Average prices shown in the table reflect both of the before-and-after effects of our realized commodity hedging transactions. Our calculation of such after-effects includes realized gains or losses on cash settlements for commodity derivatives, which do not qualify for hedge accounting because we do not designate or document them as hedges for accounting purposes. Oil production was converted at 6 Mcf per Bbl to calculate total Bcfe production and per Mcfe amounts.

* Not meaningful or applicable

Natural gas and oil sales Revenues from production of natural gas and oil decreased from $229.7 million for the year ended December 31, 2008 to $129.6 million for the year ended December 31, 2009, a decrease of $100.1 million or 43.6%. Our production increased by 15.5% from 31.0 Bcfe in 2008 to 35.8 Bcfe in 2009. The net decrease in revenues resulted from commodity price declines which accounted for a $135.7 million decrease (calculated as the decrease in year-to-year average price times current year production volumes) in revenues as partially offset by increased production volumes which increased revenues by $35.6 million (calculated as the increase in year-to-year volumes times the prior year average price). Realized gains from our commodity hedging contracts partially offset the effect of these price declines by $116.5 million. The following table sets forth additional information concerning our production volumes for the years ended December 31, 2008 and 2009:

	Years Ended December 31,		
(Bcfe)	2008	2009	Percent Change
Arkoma Woodford	18.7	23.6	26.2%
Piceance Basin	12.3	11.7	(4.8)%
Appalachia	—	0.5	
Total	31.0	35.8	15.5%

Commodity hedging activities. To achieve more predictable cash flows and to reduce our exposure to downward price fluctuations, we enter into derivative contracts using fixed for variable swap contracts when management believes that favorable future sales prices for our natural gas production can be secured. Because we do not designate these derivatives as accounting hedges, they do not receive accounting hedge treatment and all mark-to-market gains or losses, as well as realized gains or losses on the derivative instruments, are recognized in our results of operations. The unrealized gains and losses represent the changes in the fair value of these swap agreements as the future strip prices fluctuate from the fixed price we will receive on future production. For the years ended December 31, 2008 and 2009, our hedges resulted in realized gains of $26.1 million and $116.5 million, respectively. For the years ended December 31, 2008 and 2009, our hedges resulted in unrealized gains of $90.3 million and unrealized losses of $(61.2) million, respectively. Unrealized gains in 2008 occurred as commodity prices began to fall below our fixed price swaps as a result of the weakening U.S. and global economy. During 2009, we realized part of these gains as our 2009 hedge contracts matured and prices began to recover thus partially reversing the unrealized gains recorded in 2008.

Gathering and processing revenues. Gathering and processing revenues increased from $20.4 million for the year ended December 31, 2008 to $23.0 million for 2009 as our plants increased utilization and recoveries.

Lease operating expenses. Lease operating expenses increased from $13.4 million for the year ended December 31, 2008 to $17.6 million in 2009, an increase of 31.9%, primarily as a result of an increase in Arkoma Woodford production volumes and increased water disposal costs in the Piceance Basin. On a per-Mcfe basis, lease operating expenses increased in total from $0.43 per Mcfe in 2008 to $0.49 per Mcfe in 2009 because of the increase in Piceance costs vs. Arkoma costs. In August 2009, two water injection wells were completed in the Piceance Basin and we believe this will decrease future water disposal costs. The following table displays the lease operating expense per Mcfe by basin for the years ended December 31, 2008 and 2009:

	Years Ended December 31,			
	2008		2009	
(in thousands, except per Mcfe data)	Amount	Per Mcfe	Amount	Per Mcfe
Arkoma Woodford	$ 5,069	$ 0.27	$ 5,336	$ 0.23
Piceance Basin	8,281	$ 0.68	12,242	$ 1.04
Appalachia	—	—	28	$ 0.06
Total lease operating expense	$ 13,350	$ 0.43	$ 17,606	$ 0.49

Gathering, compression and transportation. Gathering, compression and transportation expense decreased from $29.0 million for the year ended December 31, 2008 to $28.2 million in 2009. On a per-Mcfe basis, these expenses decreased from $0.94 per Mcfe for 2008 to $0.79 per Mcfe for 2009 as gathering plant utilization increased and as production has increased in the Arkoma Basin as a proportion of our total production. Gathering expenses are less in the Arkoma Basin than in the Piceance Basin because of higher water production rates in the Piceance Basin.

Production taxes. Total production taxes decreased from $10.3 million for the year ended December 31, 2008 to $4.9 million for the year ended December 31, 2009, primarily as a result of a decrease in natural gas and oil prices. Production taxes as a percentage of natural gas and oil revenues before the effects of hedging were 3.8% for the year ended December 31, 2009 compared to 4.5% for the year ended December 31, 2008. Production taxes are primarily based on the wellhead values of production and the applicable rates vary across the areas in which we operate. As the proportion of our production changes from area to area, our production tax rate will vary depending on the quantities produced from each area and the applicable production tax rates then in effect.

Exploration expense. Exploration expense decreased from $23.0 million for the year ended December 31, 2008 to $10.2 million for the year ended December 31, 2009. Exploration expense during 2009 primarily consisted of $1.0 million of seismic costs, $1.7 million in dry hole costs, $5.0 million of standby rig costs and $2.5 million of contract landman costs that did not result in leasehold acquisitions. Exploration expense for 2008 primarily consisted of $5.5 million for seismic programs in the Arkoma and Piceance areas, $6.6 million of dry hole costs, $6.0 million in impairment of rig upgrades and $4.9 million of contract landman costs that did not result in leasehold acquisitions.

Impairment of unproved properties. Our impairment of unproved property expense increased from $10.1 million for the year ended December 31, 2008 to $54.2 million for the year ended December 31, 2009, primarily because at this time we believe we will not renew or drill on certain leaseholds within our Ardmore and Arkoma Basin acreage which are expiring at various dates through December 31, 2010. We abandon expired or soon to be expired leases when we determine they are impaired through lack of drilling activities or based on other factors, such as remaining lease terms, reservoir performance, commodity price outlooks or future plans to develop the acreage and recognize impairment costs accordingly.

Depreciation, depletion and amortization (DD&A). DD&A increased from $124.8 million for year ended December 31, 2008 to $139.8 million for the year ended December 31, 2009, an increase of $15.0 million, primarily as a result of increased production for 2009 compared to 2008. DD&A per Mcfe decreased slightly from $4.03 per Mcfe during 2008 to $3.91 per Mcfe during 2009.

We evaluate the impairment of our proved natural gas and oil properties on a field-by-field basis whenever events or changes in circumstances indicate that a property's carrying amount may not be recoverable. If the carrying amount exceeds the estimated undiscounted future cash flows, we reduce the carrying amount of the oil and gas properties to their estimated fair value. There were no impairment expenses recorded for the years ended December 31, 2008 or 2009 for proved properties. We had $11.9 million of exploratory well costs at December 31, 2009 included in natural gas and oil properties pending determination of whether proved reserves could be assigned to these well costs. These costs result primarily from development activity in the Marcellus Shale. As of December 31, 2009, no significant well costs have been deferred for over one year pending proved reserves determination.

General and administrative. General and administrative expense increased from $16.2 million for the year ended December 31, 2008 to $20.8 million during 2009, an increase of $4.6 million. The increase is primarily due to increased costs related to salaries, employee benefits, contract personnel and professional services expenses for additional personnel required for our capital expenditure program and production levels. On a per-Mcfe basis, general and administrative expense increased from $0.52 per Mcfe during the year ended December 31, 2008 to $0.58 per Mcfe during 2009.

Interest expense and realized and unrealized gains and losses on interest rate derivatives. Interest expense decreased from $37.6 million for the year ended December 31, 2008 to $36.1 million during 2009, a decrease of $1.5 million, primarily as a result of lower market interest rates in 2009. In November 2009, we issued $375.0 million of 9.375% senior notes, and in January 2010, we issued an additional $150.0 million of the same series of 9.375% senior notes. The fixed interest rate on these senior notes is significantly higher than the variable rate we have been paying on our bank credit facility borrowings and on our second lien debt facility (which was repaid in full with the net proceeds of the November 2009 senior notes offering). As a result, interest expense in 2010 is expected to be significantly higher than 2009 or 2008 levels.

We have entered into various variable-to-fixed interest rate swap agreements that hedge our exposure to interest rate variations on our senior secured revolving credit facility and second lien term loan facility. During 2009, we had interest rate swaps outstanding for a notional amount of $426.0 million with fixed pay rates ranging from 2.79% to 4.11% and terms expiring from December 2009 through July 2011. During the year ended December 31, 2009, we realized a loss on interest rate swap agreements of $11.1 million; whereas, during 2008 we had a realized loss on interest rate swap agreements of $1.4 million. At December 31, 2009, the estimated fair value of our interest rate swap agreements was a liability of $11.1 million, which is included in current and long-term liabilities. As of December 31, 2009, we were in a liability position on our interest rate swaps because of the large decline in interest rates since having entered into the agreements. The amount of future gain or loss actually recognized on such swaps is dependent upon future interest rates, which will affect the value of the swaps. Additionally, we did not terminate the portion of the interest rate swaps related to the $225 million second lien term loan facility when it was repaid in November 2009; therefore, a portion of our interest rate swaps do not currently have floating rate debt associated with them.

Income tax expense. Income tax expense reflects the fact that each of the operating entities files separate federal and state income tax returns; therefore, our provision for income taxes consists of the sum of our income tax provisions for each of the operating entities. In general, none of the operating entities have generated current taxable income in either the current or prior years, which is primarily attributable to the differing book and tax treatment of unrealized derivative gains and intangible drilling costs. Accordingly, valuation allowances have generally been established against net operating loss (NOLs) carryforwards to the extent that such NOLs exceed net deferred tax liabilities resulting in no income tax expense or benefit. During the year ended December 31, 2008, the operating entities had significant net income on a combined basis primarily related to unrealized derivative gains which are not taxable until realized. Net income tax expense in 2008 reflects the net deferred tax liabilities relating to these unrealized derivative gains which were partially offset by a decrease in the valuation allowance. During the year ended December 31, 2009, we recognized a tax benefit to the extent of existing deferred tax liabilities. We have not recognized the full value of these net operating losses on our balance sheets because our management team believes it is more likely than not that we will not realize a future benefit for the full amount of the loss carryforward over time. At December 31, 2009, the operating entities had a combined total of approximately $276 million of NOLs, which expire starting in 2024 and through 2029. Congress recently proposed legislation that would eliminate or limit future deductions for intangible drilling costs and could significantly affect our future taxable position. The impact of any change will be recorded in the period that legislation is enacted.

Year Ended December 31, 2007 Compared to Year Ended December 31, 2008

The following table sets forth selected operating data for the year ended December 31, 2007 compared to the year ended December 31, 2008:

(in thousands, except per unit data)	Year Ended December 31, 2007	Year Ended December 31, 2008	Amount of Increase (Decrease)	Percent Change
Operating revenues:				
Natural gas sales	$ 63,975	$ 220,219	$ 156,244	244.2%
Oil sales	3,749	9,496	5,747	153.3%
Realized commodity derivative gains	14,373	26,053	11,680	81.3%
Unrealized commodity derivative gains	4,619	90,301	85,682	1,855.0%
Gathering and processing	4,778	20,421	15,643	327.4%
Total operating revenues	91,494	366,490	274,996	300.6%
Operating expenses:				
Lease operating expense	4,435	13,350	8,915	201.0%
Gathering, compression and transportation	10,016	29,033	19,017	189.9%
Production taxes	2,233	10,281	8,048	360.4%
Exploration expense	17,970	22,998	5,028	28.0%
Impairment of unproved properties	4,995	10,112	5,117	102.4%
Depletion, depreciation and amortization	50,091	124,821	74,730	149.2%
Accretion of asset retirement obligations	68	176	108	158.8%
General and administrative	11,682	16,171	4,489	38.4%
Total operating expenses	101,490	226,942	125,452	123.6%
Operating income (loss)	(9,996)	139,548	149,544	*
Other income (expense):				
Interest expense	$ (25,124)	$ (37,594)	$ (12,470)	49.6%
Realized and unrealized interest rate derivative losses	(3,033)	(15,245)	(12,212)	402.6%
Total other expense	(28,157)	(52,839)	(24,682)	87.7%
Income (loss) before income taxes	(38,153)	86,709	124,862	*
Provision for income tax (expense) benefit	400	(3,029)	(3,429)	*
Net income (loss)	(37,753)	83,680	121,433	*
Non-controlling interest in net income of consolidated subsidiary	—	276	276	*
Net income (loss) attributable to Antero stockholders	$ (37,753)	83,956	121,709	*
Production data:				
Natural gas (Bcf)	10.9	30.3	19.4	178.0%
Oil (MBbl)	49.4	114.9	65.5	132.6%
NGLs (Bcfe)(1)	—	0.9	0.9	*
Combined (Bcfe)	11.2	31.9	20.7	184.8%
Daily combined production (MMcfe/d)	30.8	87.4	56.6	183.8%
Average prices before effects of hedges(2):				
Natural gas (per Mcf)	$ 5.85	$ 7.27	$ 1.42	24.3%
Oil (per Bbl)	$ 76.51	$ 82.57	$ 6.06	7.9%
Combined (per Mcfe)	$ 6.03	$ 7.41	$ 1.38	22.9%

(in thousands, except per unit data)	Year Ended December 31, 2007	2008	Amount of Increase (Decrease)	Percent Change
Average realized prices after effects of hedges(2) :				
Natural gas (per Mcf)	$ 6.49	$ 8.13	$ 1.64	25.3%
Oil (per Bbl)	$ 76.51	$ 82.57	$ 6.06	7.9%
Combined (per Mcfe):	$ 6.65	$ 8.25	$ 1.60	24.1%
Average costs (per Mcfe):				
Lease operating costs	$ 0.39	$ 0.43	$ 0.04	10.3%
Gathering, compression and transportation	$ 0.89	$ 0.94	$ 0.05	5.6%
Production taxes	$ 0.20	$ 0.33	$ 0.13	65.0%
Depletion, depreciation, amortization	$ 4.46	$ 4.03	$ (0.43)	(9.6)%
General and administrative	$ 1.04	$ 0.52	$ (0.52)	(50.0)%

(1) Represents NGLs retained by our midstream business as compensation for processing third-party gas under long term contracts. These amounts are not reflected in the per Mcfe data in this table.

(2) Average prices shown in the table reflect both of the before-and-after effects of our realized commodity hedging transactions. Our calculation of such after-effects includes realized gains or losses on cash settlements for commodity derivatives, which do not qualify for hedge accounting because we do not designate or document them as hedges. Oil production was converted at 6 Mcf per Bbl to calculate total Bcfe production and per Mcfe amounts.

* Not meaningful or applicable.

Natural gas and oil sales. Revenues from sales of natural gas and oil increased to $229.7 million for the year ended December 31, 2008 from $67.7 million for the year ended December 31, 2007, an increase of 239%. Our annual production increased by 176.8% from 11.2 Bcfe in 2007 to 31.0 Bcfe in 2008 due to increased production in the Arkoma Woodford and Piceance Basins. This net increase in production added approximately $119.1 million of production revenues, and the increase in prices on a per-Mcfe basis increased production revenues by approximately $42.9 million. The following table presents additional information concerning our production for the years ended December 31, 2007 and 2008:

(in Bcfe)	Year Ended December 31, 2007	2008	Percent Increase
Arkoma Woodford	6.3	18.7	196.8%
Piceance Basin	4.9	12.3	151.0%
Total	11.2	31.0	176.8%

Commodity hedging activities. To achieve more predictable cash flows and to reduce our exposure to downward price fluctuations, we enter into derivative contracts using fixed for variable swap contracts when management believes that favorable future sales prices for our natural gas production can be secured. Because we do not designate these derivatives as accounting hedges, they do not receive accounting hedge treatment and all mark-to-market gains or losses, as well as realized gains or losses on the derivative instruments, are currently recognized in our results of operations. The unrealized gains and losses represent the changes in the fair value of these swap agreements as the future strip prices fluctuate from the fixed price we will receive from future production. In 2008, approximately 59% of our natural gas volumes were hedged, which resulted in a realized gain on such hedges of $26.1 million. In 2007, we hedged approximately 81% of our natural gas volumes, which resulted in realized gains on such hedges of $14.4 million. Unrealized gains in these periods were

$4.6 million and $90.3 million in 2007 and 2008, respectively. The significant unrealized gains in 2008 are attributable to the sharp decline in natural gas prices in the fourth quarter as a result of market turmoil and a weakened U.S. and global economy.

Gathering and processing revenues. Gathering and processing revenues increased from $4.8 million in 2007 to $20.4 million in 2008 primarily as a result of recognizing a full year of operations for our Coalgate plant in Oklahoma, which began processing volumes in September 2007. Additionally, in February 2008, we entered into a joint venture with MarkWest and began operating our two processing plants under our Centrahoma joint venture.

Lease operating expense. Lease operating expenses increased from $4.4 million in 2007 to $13.4 million in 2008, an increase of 201% primarily as a result of an increase in our production volumes. On a per-Mcfe basis, lease operating expenses increased from $0.39 per Mcfe in 2007 to $0.43 per Mcfe in 2008 primarily due to increased water disposal expenses in the Piceance Basin. The following table displays our lease operating expenses per Mcfe by basin:

	Year Ended December 31,			
	2007		2008	
(in thousands, except per Mcfe data)	Amount	Per Mcfe	Amount	Per Mcfe
Arkoma Woodford	$ 1,758	$ 0.28	$ 5,069	$ 0.27
Piceance Basin	$ 2,677	$ 0.54	$ 8,281	$ 0.68
Total lease operating expense	$ 4,435	$ 0.39	$ 13,350	$ 0.43

Gathering, compression and transportation. Gathering and transportation expense increased from $10.0 million in 2007 to $29.0 million in 2008 primarily as a result of an increase in production. On a per-Mcfe basis, these expenses increased from $0.89 per Mcfe in 2007 to $0.94 per Mcfe as a result of start-up expenses for the Coalgate plant.

Production taxes. Total production taxes increased from $2.2 million in 2007 to $10.3 million in 2008 primarily as a result of an increase in natural gas and oil revenues before the effects of hedging. Production taxes as a percentage of natural gas and oil revenues before the effects of hedging were 4.5% for 2008 and 3.3% for 2007. Production taxes are primarily based on the wellhead values of production, and the tax rates vary across the different areas in which we operate. As the proportion of our production changes from area to area, our production tax rate will vary depending on the quantities produced from each area and the production tax rates in effect.

Exploration expense. Exploration expense increased from $18.0 million in 2007 to $23.0 million in 2008. Exploration expense for 2008 consisted of $5.5 million for seismic programs in the Arkoma and Piceance areas, $6.6 million in dry hole costs, $6.0 million in impairment of rig upgrades and $4.9 million of contract landman costs that did not result in leasehold acquisitions. Exploration expense for 2007 consisted of $9.8 million for seismic programs in the Arkoma Woodford and Piceance areas, $4.4 million of dry hole costs and $3.8 million of contract landman costs that did not result in leasehold acquisitions.

Impairment of unproved properties. Our impairment of unproved property expense increased from $5.0 million in 2007 to $10.1 million in 2008, primarily because we elected to abandon certain leaseholds within our Ardmore Basin acreage and certain non-core Arkoma Basin acreage. We abandon expired or soon to be expired leases when we determine they are impaired through lack of drilling activities or based on other factors, such as remaining lease terms, reservoir performance, commodity price outlook or future plans to develop the acreage and accordingly recognize corresponding impairment costs.

Depreciation, depletion and amortization (DD&A). DD&A increased from $50.1 million in 2007 to $124.8 million in 2008, an increase of $74.7 million, primarily as a result of increased production in 2008 as compared to 2007. The weighted average DD&A rate decreased from $4.46 per Mcfe during 2007 to $4.03 per Mcfe during 2008 because our exploration, development and acquisition costs (total funding costs) have declined on a per Mcf basis in our two primary producing areas.

Under successful efforts accounting, DD&A expense is separately computed for each producing area based on geologic and reservoir delineation. The capital expenditures for each producing area compared to the proved reserves corresponding to each producing area determine a weighted average DD&A rate for current production. Future DD&A rates will be adjusted to reflect future capital expenditures and proved reserve changes in specific areas. We anticipate that DD&A expense per unit will decline over time as our development projects mature.

We evaluate the impairment of our proved natural gas and oil properties on a field-by-field basis whenever events or changes in circumstances indicate that a property's carrying amount may not be recoverable. If the carrying amount exceeds the property's estimated fair value, we adjust the carrying amount of the property to fair value through a charge-to-impairment expense. There were no impairment expenses recorded in 2007 or 2008 for proved properties. Additionally, there were no exploratory wells in progress at December 31, 2007 or 2008 included in unevaluated natural gas and oil properties pending determination of whether proved reserves could be assigned to any such wells.

General and administrative. General and administrative expense increased from $11.7 million in 2007 to $16.2 million in 2008, an increase of $4.5 million, primarily as a result of increased costs of $2.7 million related to salaries and employee benefits for additional personnel required for our capital program and production activities. As of December 31, 2008, we had 56 full-time employees, compared to 40 full-time employees as of December 31, 2007. On a per-Mcfe basis, general and administrative expense decreased from $1.04 per Mcfe in 2007 to $0.52 per Mcfe in 2008 primarily as a result of an increase in production volumes without a corresponding increase in general and administrative expense.

Interest expense and realized and unrealized gains and losses on interest rate derivatives. Interest expense increased from $25.1 million in 2007 to $37.6 million in 2008, primarily as a result of higher average outstanding debt balances in 2008 in order to fund our exploration and development activities. While interest rates on our senior secured revolving credit facility and second lien term loan facility decreased during 2008 from 2007 levels, average borrowings outstanding increased from approximately $259.5 million during 2007 to approximately $538.1 million during 2008.

We have entered into various variable-to-fixed interest rate swap agreements that hedge our exposure to interest rate variations on our senior secured revolving credit facility and second lien term loan facility. At December 31, 2008, we had interest rate swaps outstanding for a notional amount of $426.0 million with fixed pay rates ranging from 2.79% to 4.11% and terms expiring from December 2009 through July 2011. During 2008, we realized losses on interest rate swap agreements of $1.4 million, whereas, during 2007, we realized a gain on interest rate swap agreements of $0.4 million. At December 31, 2008, the estimated fair value of our interest rate swap agreements was a liability of $17.3 million, which is included in current and long-term liabilities. As of such date, we were in a liability position on our interest rate swaps because of the large decline in interest rates since having entered into the agreements. The amount of future gain or loss actually recognized on such swaps is dependent upon future interest rates, which will affect the value of the swaps.

Income tax expense. Income tax expense reflects the fact that each of the operating entities files separate federal and state income tax returns; therefore our provision for income taxes consists of the sum of our income tax provisions for each of the operating entities. In general, none of the operating entities have generated current taxable income in either the current or prior years, which is primarily attributable to the differing book and tax treatment of unrealized derivative gains and intangible drilling costs. Accordingly, valuation allowances have generally been established against net operating loss (NOLs) carryforwards to the extent that such NOLs exceed net deferred tax liabilities resulting in no income tax expense or benefit in prior years. During the year ended December 31, 2008, the operating entities had significant net income on a combined basis primarily related to unrealized derivative gains which are not taxable until realized and, accordingly, we recognized related deferred tax expense. This deferred income tax expense was substantially offset by a reduction in valuation allowances. At December 31, 2008, the operating entities had a combined total of approximately $156.9 million of NOLs, which expire starting in 2024 and through 2029. We have not recognized the full value of these net operating losses on our balance sheets because our management team believes it is more likely than not that we will not realize a future benefit for the full amount of the loss carryforward over time. Congress recently proposed legislation that would eliminate or limit future deductions for intangible drilling costs and could adversely affect our future taxable position. The impact of any change is recorded in the period that legislation is enacted.

Three Months Ended March 31, 2009 Compared to Three Months Ended March 31, 2010

The following table sets forth selected operating data for the three months ended March 31, 2009 compared to the three months ended March 31, 2010:

(in thousands, except per unit data)	Three Months Ended March 31, 2009	2010	Amount of Increase (Decrease)	Percent Change
Operating revenues:				
Natural gas sales	$ 37,332	53,952	16,620	44.5%
Oil sales	1,063	2,114	1,051	98.9%
Realized commodity derivative gains	33,572	12,271	(21,301)	(63.4)%
Unrealized commodity derivative gains (losses)	5,114	98,812	93,698	1,832.2%
Gathering and processing	4,379	6,413	2,034	46.4%
Total operating revenues	81,460	173,562	92,102	113.1%
Operating expenses:				
Lease operating expense	6,945	4,598	(2,347)	(33.8)%
Gathering compression and transportation	6,375	10,141	3,766	59.1%
Production taxes	1,832	2,670	838	45.7%
Exploration expense	2,429	1,352	(1,077)	(44.3)%
Impairment of unproved properties	7,767	2,262	(5,505)	(70.9)%
Depletion, depreciation and amortization	39,701	32,996	(6,705)	(16.9)%
Accretion of asset retirement obligations	62	73	11	17.7%
General and administrative	4,406	4,412	6	0.1%
Total operating expenses	69,517	58,504	(11,013)	(15.8)%
Operating income (loss)	11,943	115,058	103,115	863.4%

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(in thousands, except per unit data)	Three Months Ended March 31, 2009	2010	Amount of Increase (Decrease)	Percent Change
Other income expense:				
Interest expense	(7,178)	(13,292)	(6,114)	85.2%
Realized interest rate derivative gains (losses)	(2,072)	(3,127)	(1,055)	50.9%
Unrealized interest rate derivative gains (losses)	697	1,525	828	118.8%
Total other income expense	(8,553)	(14,894)	(6,341)	74.1%
Income (loss) before income taxes	3,390	100,164	96,774	*
Provision for income taxes (expense) benefit	1,605	(11,318)	(12,923)	*
Net income (loss)	4,995	88,446	83,451	*
Non-controlling interest in net (loss) income of consolidated subsidiary	159	(1,241)	(1,400)	*
Net income (loss) attributable to Antero stockholders	$ 5,154	$ 87,605	$ 82,451	*
Production data:				
Natural gas (Bcf)	9.7	9.9	0.2	2.1%
Oil (MBbl)	30.8	31.9	1.1	3.6%
NGLs (Bcfe)(1)	0.7	0.5	(0.2)	(28.6)%
Combined (Bcfe)	10.6	10.6	0.0	0.0%
Average prices before effects of hedges(2):				
Natural gas (per Mcf)	$ 3.84	$ 5.47	$ 1.63	42.4%
Oil (per Bbl)	$ 34.51	$ 66.27	$ 31.76	92.0%
Combined (per Mcfe)	$ 3.87	$ 5.57	$ 1.70	43.9%
Average realized prices after effects of hedges(2):				
Natural gas (per Mcf)	$ 7.28	$ 6.71	$ (0.57)	(7.8)%
Oil (per Bbl)	$ 34.51	$ 66.27	$ 31.76	92.0%
Combined (per Mcfe)	$ 7.26	$ 6.79	$ (0.47)	(6.5)%
Average Costs (per Mcfe):				
Lease operating costs	$ 0.70	$ 0.46	$ (0.24)	(34.3)%
Gathering, compression and transportation	$ 0.64	$ 1.01	$ 0.37	57.8%
Production taxes	$ 0.18	$ 0.27	$ 0.09	50.0%
Depletion, depreciation, amortization and accretion	$ 4.00	$ 3.28	$ (0.72)	(18.0)%
General and administrative	$ 0.44	$ 0.44	$ 0.00	0.0%

(1) Represents NGLs retained by our midstream business as compensation for processing third-party gas under long term contracts. These amounts are not reflected in the per Mcfe data in this table.

(2) Average prices shown in the table reflect both of the before-and-after effects of our realized commodity hedging transactions. Our calculation of such after-effects includes realized gains or losses on cash settlements for commodity derivatives, which do not qualify for hedge accounting because we do not designate or document them as hedges for accounting purposes. Oil production was converted at 6 Mcf per Bbl to calculate total Bcfe production and per Mcfe amounts.

* Not meaningful or applicable

Natural gas and oil sales. Revenues from production of natural gas and oil increased from $38.4 million for the three months ended March 31, 2009 to $56.1 million for the three months ended March 31, 2010, an increase of 46%. Our production increased slightly, from 9.9 Bcfe for the three months ended March 31, 2009 to 10.1 Bcfe for the three months ended March 31, 2010; however, prices increased by 44% before the effect of realized hedge gains. After the effect of realized hedge gains, our realized price per Mcfe decreased from $7.26 per Mcfe for the three months ended March 31, 2009 to $6.79 per Mcfe for the 2010 period. The net increase in realized oil and gas revenues resulted from production increases, which accounted for a $0.6 million increase in revenues, and price increases which increased revenues by $17.1 million. The following table sets forth additional information concerning our production volumes for the three months ended March 31, 2009 and 2010:

(Bcfe)	Three Months Ended March 31, 2009	2010	Percent Change
Arkoma Woodford	6.6	5.9	(11)%
Piceance Basin	3.3	2.7	(18)%
Appalachia	—	1.5	
Total	9.9	10.1	2.0%

Commodity hedging activities. To achieve more predictable cash flows and to reduce our exposure to downward price fluctuations, we enter into derivative contracts using fixed for variable swap contracts when management believes that favorable future sales prices for our natural gas production can be secured. Because we do not designate these derivatives as accounting hedges, they do not receive accounting hedge treatment and all mark-to-market gains or losses, as well as realized gains or losses on the derivative instruments, are recognized in our results of operations. The unrealized gains and losses represent the changes in the fair value of these swap agreements as the future strip prices fluctuate from the fixed price we will receive on future production. For the three months ended March 31, 2009 and 2010, our hedges resulted in realized gains of $33.6 million and $12.3 million, respectively. For the three months ended March 31, 2009 and 2010, our hedges resulted in unrealized gains of $5.1 million and $98.8 million, respectively. Unrealized gains occurred as commodity prices at March 31, 2009 and 2010 were below our fixed price swaps. Should natural gas prices increase from their March 31, 2010 levels, these unrealized gains at March 31, 2010 will reverse.

Gathering and processing revenues. Gathering and processing revenues increased from $4.4 million for the three months ended March 31, 2009 to $6.4 million for the three months ended March 31, 2010 because of increased utilization and recoveries and increases in prices received for NGLs from the prior year period.

Lease operating expenses. Lease operating expenses decreased from $6.9 million for the three months ended March 31, 2009 to $4.7 million for the three months ended March 31, 2010, a decrease of 31.9%, primarily as a result of the decrease in water disposal costs in the Piceance Basin. On a per-Mcfe basis, lease operating expenses decreased from $0.70 per Mcfe for the three months ended March 31, 2009 to $0.47 per Mcfe for the respective 2010 period. In August 2009, two water injection wells were completed in the Piceance Basin which decreased water disposal costs compared to the prior year period. The following table displays the lease operating expense per Mcfe by basin for the three months ended March 31, 2009 and 2010:

	Three months ended March 31, 2009		2010	
(in thousands, except per Mcfe data)	Amount	Per Mcfe	Amount	Per Mcfe
Arkoma Woodford	$ 1,692	$ 0.25	$ 1,356	$ 0.23
Piceance Basin	5,253	$ 1.60	2,915	$ 1.07
Appalachia	—	—	327	$ 0.22
Total lease operating expense	$ 6,945	$ 0.70	$ 4,598	$ 0.46

Gathering, compression and transportation. Gathering, compression and transportation expense increased from $6.4 million for the three months ended March 31, 2009 to $10.1 million for the three months ended March 31, 2010. On a per-Mcfe basis, these expenses increased from $0.64 per Mcfe for the three months ended March 31, 2009 to $1.01 per Mcfe for the 2010 period primarily because of increased contractual transportation costs for Arkoma Woodford and Piceance basin production related to new transportation contracts. Increased transportation costs were partially offset by increased pricing received at new delivery points.

Production taxes. Total production taxes increased from $1.8 million for the three months ended March 31, 2009 to $2.6 million for the three months ended March 31, 2010, primarily as a result of the increase in natural gas and oil prices. Production taxes as a percentage of natural gas and oil revenues before the effects of hedging were 4.8% for the three months ended March 31, 2009 and 4.7% for the three months ended March 31, 2010. Production taxes are primarily based on the wellhead values of production and the applicable rates vary across the areas in which we operate. As the proportion of our production changes from area to area, our production tax rate will vary depending on the quantities produced from each area and the applicable production tax rates then in effect.

Exploration expense. Exploration expense decreased from $2.4 million for the three months ended March 31, 2009 to $1.4 million for the three months ended March 31, 2010, primarily because of $0.9 million in impairment charges related to rig update costs during the three months ended March 31, 2009.

Impairment of unproved properties. Our impairment of unproved property expense decreased from $7.8 million for the three months ended March 31, 2009 to $2.3 million for the three months ended March 31, 2010. We had higher costs in the prior year because we elected to abandon certain leaseholds within our non-core Ardmore Basin acreage and certain non-core Arkoma Basin acreage. We abandon expired or soon to be expired leases when we determine they are impaired through lack of drilling activities or based on other factors, such as remaining lease terms, reservoir performance, commodity price outlooks or future plans to develop the acreage and recognize impairment costs accordingly.

Depreciation, depletion and amortization (DD&A). DD&A decreased from $39.7 million for three months ended March 31, 2009 to $33.0 million for the three months ended March 31, 2010, a decrease of $6.7 million, primarily as a result of increased proved developed reserve quantities in 2010 compared to 2009 because of changes in pricing due to new SEC rules, which affected our depletion rates beginning with the fourth quarter of 2009. Production rates also decreased in the Arkoma and Piceance basins. DD&A per Mcfe decreased from $4.00 per Mcfe during the three months ended March 31, 2009 to $3.27 per Mcfe during the three months ended March 31, 2010.

We evaluate the impairment of our proved natural gas and oil properties on a field-by-field basis whenever events or changes in circumstances indicate that a property's carrying amount may not be recoverable. If the carrying amount exceeds the estimated undiscounted future cash flows, we reduce the carrying amount of the oil and gas properties to their estimated fair value. There were no impairment expenses recorded for the three months ended March 31, 2009 or 2010 for proved properties. As of March 31, 2010, no significant well costs have been deferred for over one year pending proved reserves determination.

General and administrative. General and administrative expenses remained constant at $4.4 million for the three months ended March 31, 2009 and 2010. Increased salaries and benefits for the three months ended March 31, 2010 compared to the three months end March 31, 2009 due to the addition of full-time personnel of approximately $0.5 million were offset by decreases in stock compensation expense, franchise tax expense, and miscellaneous other expenses. On a per-Mcfe basis, general and administrative expense remained constant at $0.44 per Mcfe for the three months ended March 31, 2009 and 2010.

Interest expense and realized and unrealized gains and losses on interest rate derivatives. Interest expense increased from $7.2 million for the three months ended March 31, 2009 to $13.3 million for the three months ended March 31, 2010 because of the issuance of $375.0 million of 9.375% senior notes in November 2010 and $150 million of the same series of notes in January 2010. The fixed interest rate on these senior notes is significantly higher than the variable rates we paid during the first three months of 2009 on borrowings under our senior secured revolving credit facility and the second lien term loan facility (which were the primary sources of borrowings during the three months ended March 31, 2009).

As of March 31, 2010, we had an interest rate swap outstanding for a notional amount of $225 million with a fixed pay rate of 4.11% with a term expiring July 2011. During the three months ended March 31, 2009, we realized a loss on interest rate swap agreements of $2.1 million; whereas, during the three months ended March 31, 2010 we had a realized loss on interest rate swap agreements of $3.1 million. At March 31, 2010, the estimated fair value of our interest rate swap was a liability of $9.6 million, which is included in current and long-term liabilities. As of March 31, 2010, we were in a liability position on our interest rate swap because of the large decline in interest rates since having entered into the agreement. The amount of future gain or loss actually recognized on such swap is dependent upon future interest rates, which will affect the value of the swaps. We did not terminate the interest rate swap related to the $225 million second lien term loan facility when it was repaid in November 2009; therefore, this swap does not currently have floating rate debt associated with it. As of March 31, 2010, there were no borrowings outstanding under the senior secured revolving credit facility.

Income tax expense. Income tax expense reflects the fact that each of the operating entities files separate federal and state income tax returns; therefore, our provision for income taxes consists of the sum of our income tax provisions for each of the operating entities. None of the operating entities have generated current taxable income in either the current or prior periods, which is primarily attributable to the differing book and tax treatment of unrealized derivative gains and intangible drilling costs. Accordingly, valuation allowances have generally been established against net operating loss (NOLs) carryforwards to the extent that such NOLs and other deferred tax assets exceed deferred tax liabilities resulting in no income tax expense or benefit for those subsidiaries having deferred tax assets in excess of deferred tax liabilities. We have not recognized the full value of these NOLs on our balance sheets because our management team believes it is more likely than not that we will not realize a future benefit for the full amount of the loss carryforwards over time.

Certain subsidiaries had net deferred tax liabilities at March 31, 2010, resulting from unrealized gains on commodity derivatives and basis differences in assets, resulting in the provision of $11.3 million of deferred tax expense during the first quarter of 2010.

The tax benefit of $1.6 million for the three months ended March 31, 2009 resulted from the reversal of previously recorded deferred tax liabilities as a result of operating losses incurred in the first quarter of 2009 by one of the operating entities.

At December 31, 2009, the operating entities had a combined total of approximately $276 million of NOLs, which expire starting in 2024 and through 2029. Congress recently proposed legislation that would eliminate or limit future deductions for intangible drilling costs and could significantly affect our future taxable position. The impact of any change is recorded in the period that legislation is enacted.

Capital Resources and Liquidity

Our primary sources of liquidity have been through issuances of equity securities, borrowings under bank credit facilities, our second lien term loan facility, our senior notes, and net cash provided by operating activities. Our primary use of cash has been for the exploration, development and acquisition of natural gas and oil properties. As we pursue reserve and production growth, we continually monitor what capital resources, including equity and debt financings, are available to meet our future financial obligations, planned capital expenditure activities and liquidity requirements. Our future success in growing proved reserves and production will be highly dependent on the capital resources available to us. We have approximately 16,000 potential drilling locations, of which only approximately 9.8% are included in our proved reserve base as of December 31, 2009. We would be required to generate or raise significant capital to conduct drilling activities on these potential drilling locations.

In November 2009, we adjusted our capital structure by issuing $375 million of 9.375% senior notes due 2017 at a discount of $2.6 million and approximately $124 million of additional equity. The net proceeds of the November 2009 senior notes offering and equity offerings were used to repay in full our $225 million second lien term loan facility, which was due to mature in 2014, and to repay a portion of the borrowings outstanding under our senior secured revolving credit facility. In January 2010, we issued an additional $150 million of the same series of 9.375% senior notes at a premium of $6 million and used the net proceeds to repay the remaining outstanding borrowings under the senior secured revolving credit facility. At March 31, 2010, we had a borrowing base under the bank credit facility of $369 million and $11.4 million of outstanding letters of credit, giving us net available borrowings on the facility of approximately $357.6 million. On May 12, 2010, the borrowing base was redetermined at $400 million (the maximum available under the facility), providing us with available borrowing capacity as of such date of approximately $361 million.

Our hedge position provides us with additional liquidity as it provides us with the relative certainty of receiving a significant portion of our future expected cash flows from operations despite potential further declines in the price of natural gas. Our ability to make significant additional acquisitions for cash would require us to obtain additional equity or debt financing, which we may not be able to obtain on terms acceptable to us, or at all. Over the last two years, dislocations in the credit markets, steep stock market declines, financial institution failures and government capital infusions reflected a weakened global economy and financing transactions have been difficult to complete as a result. Our current senior secured revolving credit facility is backed by a syndicate of 13 banks. We believe that our current syndicate banks have the capability to fund up to their current commitment. If one or more banks should not be able to do so, we may not have the full availability of our credit facility.

We believe that funds from operating cash flows and available borrowings under our senior secured revolving credit facility should be sufficient to meet our cash requirements, including normal operating needs, debt service obligations, capital expenditures, and commitments and contingencies for at least the next 12 months.

For more information on our outstanding indebtedness, see "—Cash Flow Provided by Financing Activities."

Cash Flow Provided by Operating Activities

Net cash provided by operating activities was $24.7 million, $157.5 million and $149.3 million for the years ended December 31, 2007, 2008 and 2009, respectively, and $66.6 million and $52.0 million for the three months ended March 31, 2009 and 2010, respectively. The decrease in cash flow from operations from 2008 to 2009 was primarily the result of lower gas prices in 2009. The increase in cash flow from operations for the year ended December 31, 2008 compared to 2007 was primarily the result of an increase in natural gas and oil production and prices. The decrease in cash flows for the three months ended March 31, 2009 compared to the three months ended March 31, 2010 was the result of the decrease in realized prices for production after the effect of hedges and changes in working capital levels.

Our operating cash flow is sensitive to many variables, the most significant of which is the volatility of prices for natural gas and oil production. Prices for these commodities are determined primarily by prevailing market conditions. Regional and worldwide economic activity, weather, infrastructure capacity to reach markets and other variable factors influence market conditions for these products. These factors are beyond our control and are difficult to predict. For additional information on the impact of changing prices on our financial position, see—Quantitative and Qualitative Disclosure About Market Risk" below.

Cash Flow Used in Investing Activities

During the years ended December 31, 2007, 2008 and 2009 and the three months March 31, 2009 and 2010, we had cash flows used in investing activities of $600.9 million, $1.0 billion, $281.9 million, $115.3 million and $66.0 million, respectively, as a result of our capital expenditures for drilling, development and acquisition costs. The decrease in cash used in investing activities in 2009 from 2008 of $722 million is a result of the $361.4 million investment in the Appalachian Basin in 2008 and curtailed investment and drilling activity in 2009 in all our projects in response to the decline in oil and gas prices in 2009. The increase in cash flows used in investing activities during the year ended December 31, 2008 compared to the prior year period is a result of an increase in the capital program in the Piceance Basin as well as leasehold acquisition costs incurred in the Appalachian Basin totaling $361.4 million. The decrease in cash used in investing activities for the three months ended March 31, 2009 compared to the three months ended March 31, 2010 was a result of lower levels of drilling activity. We expect that our cash used in investing activities for the remainder of 2010 will be at a higher quarterly rate based on our current capital budget and planned drilling activities.

Our capital expenditures for drilling, development and acquisition costs for the years ended December 31, 2007, 2008 and 2009 are summarized in the following table. Capital expenditures reflected in the table below differ from the amounts shown in the statements of cash flows in the financial statements because amounts reflected in the table include changes in accounts payable from the previous reporting period for capital expenditures, while the amounts in the statements of cash flows in the financial statements are presented on a cash basis.

	Year Ended December 31,		
(in thousands)	2007	2008	2009
Arkoma Basin	$ 409,465	$ 335,516	$ 77,841
Piceance Basin	147,094	297,285	51,250
Appalachian Basin	—	361,379	68,355
Gas plant, gathering, pipeline, and other	89,910	47,568	6,008
Total capital expenditures	$ 646,469	$ 1,041,748	$ 203,454

Our board of directors has approved a capital budget of up to $366 million for 2010. Our capital budget may be adjusted as business conditions warrant. The amount, timing and allocation of capital expenditures is largely discretionary and within our control. If natural gas and oil prices decline to levels below our acceptable levels or costs increase to levels above our acceptable levels, we could choose to defer a significant portion of our budgeted capital expenditures until later periods to achieve the desired balance between sources and uses of liquidity and prioritize capital projects that we believe have the highest expected returns and potential to generate near-term cash flow. We routinely monitor and adjust our capital expenditures in response to changes in prices, availability of financing, drilling and acquisition costs, industry conditions, the timing of regulatory approvals, the availability of rigs, success or lack of success in drilling activities, contractual obligations, internally generated cash flow and other factors both within and outside our control.

Cash Flow Provided by Financing Activities

Net cash provided by financing activities in 2009 of $104.3 million was primarily the result of cash provided by, (i) the issuance of the senior notes (net of discounts and issuance costs) of $361 million,

(ii) the issuance of preferred stock of $105.0 million, and (iii) the issuance of member units in Antero Resources LLC for $123.6 million (net of $1.4 million of issuance costs); net of cash applied to (i) net repayments on the bank credit facility of $254.5 million and (ii) the repayment of the second lien term loan facility of $225.0 million.

Net cash provided by financing activities of $874.4 million during the year ended December 31, 2008 was primarily the result of the issuance of $670.0 million of Series B preferred stock and $207.2 million of net borrowings under our senior secured revolving credit facility. Net cash provided by financing activities of $585.3 million during the year ended December 31, 2007 was primarily the result of the issuance of $253.8 million of preferred stock, borrowings of $225.0 million under the second lien term loan facility, and $106.9 million of net borrowings on our senior secured revolving credit facility.

Net cash provided by financing activities for the three months ended March 31, 2009 of $9.7 million was the result of the issuance of $105 million of preferred stock, the proceeds of which were used to reduce borrowings outstanding under our senior secured revolving credit facility by $90 million and to pay cash financing costs of $6.4 million. Net cash provided by financing activities of $9.6 million for the three months ended March 31, 2010 was the result of the issuance of $150 million of 9.375% senior notes at a premium of $6 million, the proceeds of which were used to reduce borrowings outstanding under our senior secured revolving credit facility by $142.1 million and to pay cash financing costs of $4.2 million.

Senior Secured Revolving Credit Facility. Our senior secured revolving credit facility was amended and restated as of January 14, 2009 and amended in October and November 2009 and in January and May 2010 and matures on March 15, 2012. As of March 31, 2010, we had letters of credit outstanding under our senior secured revolving credit facility of approximately $11 million and a borrowing base thereunder of $369 million. On May 12, 2010, the borrowing base under our senior secured revolving credit facility was redetermined at $400 million (the maximum available under the facility). As of such date, after giving effect to the redetermination, we had approximately $361 million of available borrowing capacity under our senior secured revolving credit facility. Future borrowing bases will be computed based on proved natural gas and oil reserves and estimated future cash flow from these reserves and hedge positions, as well as any other outstanding indebtedness. The borrowing base is redetermined semiannually; the next redetermination is scheduled to occur in October 2010. Following the next scheduled borrowing base redetermination, we may be subject to similar restrictions on our ability to incur indebtedness or our borrowing base may be reduced.

Principal amounts borrowed are payable on the maturity date with such borrowings bearing interest that is payable quarterly. We have a choice of borrowing in Eurodollars or at the base rate. Eurodollar loans bear interest at a rate per annum equal to the rate appearing on the Reuters BBA Libor Rates Page 3750 for one, two, three, six or twelve months plus an applicable margin ranging from 200 to 300 basis points, depending on the percentage of our borrowing base utilized. Base rate loans bear interest at a rate per annum equal to the greatest of (i) the agent bank's reference rate, (ii) the federal funds effective rate plus 50 basis points and (iii) the rate for one month Eurodollar loans, plus an applicable margin ranging from 100 to 200 basis points, depending on the percentage of our borrowing base utilized. The amounts outstanding under the facility are secured by a first priority lien on substantially all of our natural gas and oil properties and associated assets and are cross-guaranteed by each borrower entity along with each of their current and future wholly owned subsidiaries. For information concerning the effect of changes in interest rates on interest payments under this facility, see "—Quantitative and Qualitative Disclosure About Market Risk—Interest Rate Risks and Hedges."

As of December 31, 2008 and 2009, borrowings outstanding under our senior secured revolving credit facility totaled $396.6 million and $142.1 million, respectively, and had a weighted average interest rate (excluding the impact of our interest rate swaps) of 5.0% and 2.36%, respectively. At

March 31, 2010, we had no borrowings and $11.4 million of letters of credit outstanding under the senior secured revolving credit facility. The facility contains restrictive covenants that may limit our ability to, among other things:

- incur additional indebtedness;
- sell assets;
- make loans to others;
- make investments;
- enter into mergers;
- make certain payments to Antero;
- incur liens; and
- engage in certain other transactions without the prior consent of the lenders.

The senior revolving credit facility also requires us to maintain the following two financial ratios:

- a current ratio, which is the ratio of our consolidated current assets to our consolidated current liabilities, of not less than 1.0 to 1.0 as of the end of each fiscal quarter; and
- a leverage ratio, which is the ratio of our consolidated funded indebtedness (minus amounts of unsatisfied capital calls) as of the end of such fiscal quarter to our consolidated EBITDAX for the trailing four fiscal quarter period, of not greater than 4.0 to 1.0.

We were in compliance with such covenants and ratios as of December 31, 2009 and 2008 and as of March 31, 2010.

Second Lien Term Loan Facility. We repaid our $225.0 million second lien term loan facility in full with the net proceeds of the November 2009 offering of notes. The principal amount borrowed under the second lien term loan facility was payable on the maturity date, with such amount borrowed bearing interest, payable quarterly. Interest accrued on Eurodollar loans at a rate per annum equal to the Eurodollar rate, plus an applicable margin of 450 basis points. Interest accrued on base rate loans at a rate per annum equal to the greater of (i) the prime lending rate as set forth on the British Banking Association Telerate Page 5 and (ii) the federal funds effective rate plus 50 basis points, plus an applicable margin of 350 basis points. The amounts outstanding under the second lien term loan facility were secured by a second priority lien on substantially all of our natural gas and oil properties and associated assets and are cross-guaranteed by each borrower entity along with each of their current and future wholly owned subsidiaries. The second lien term loan facility contained various covenants including restrictions on our ability to incur indebtedness, dispose of assets, make loans or investments or certain payments, or enter into mergers. The second lien term loan facility also required us to maintain certain financial ratios, including interest coverage, leverage and net present value to funded indebtedness. We were in compliance with such covenants and ratios at December 31, 2008.

Interest Rate Hedges. We have entered into various variable to fixed interest rate swap agreements which hedge our exposure to interest rate variations on our senior secured revolving credit facility and second lien term loan facility. At March 31, 2010, we had an interest rate swap outstanding for a notional amount of $225.0 million with a fixed pay rate of 4.11% with a term expiring in July 2011. During the years ended December 31, 2007, 2008 and 2009 and the three months ended March 31, 2009 and 2010, we had realized gains (losses) on interest rate swap agreements of $0.4 million, $(1.4) million, $(11.1) million, $2.1 million and $3.1 million, respectively. At March 31, 2010, we had unrealized losses on our interest rate swap agreement of $9.6 million. The amount of future gain or loss actually recognized on such swap is dependent upon future interest rates. See "—Quantitative and Qualitative Disclosure About Market Risk—Interest Rate Risk and Hedges." We did not terminate the interest rate swap related to the $225.0 million second lien term facility when it was retired in November 2009; therefore, this swap does not currently have debt associated with it.

Capital Leases. We lease certain compressors under agreements that are classified as capital leases having a balance of approximately $1.3 million, $1.2 million and $1.1 million at December 31, 2008 and 2009 and March 31, 2010, respectively.

Commodity Hedging Activities

Our primary market risk exposure is in the price we received for our natural gas and oil production. Realized pricing is primarily driven by the prevailing worldwide price for crude oil and spot regional market prices applicable to our U.S. natural gas production. Pricing for natural gas and oil production has been volatile and unpredictable for several years, and we expect this volatility to continue in the future. The prices we receive for production depend on many factors outside of our control, including volatility in the differences between product prices at sales points and the applicable index price.

To mitigate some of the potential negative impact on our cash flow caused by changes in natural gas prices, we have entered into financial commodity swap contracts to receive fixed prices for a portion of our natural gas and oil production when management believes that favorable future prices can be secured. We typically hedge a fixed price for natural gas at our sales points (New York Mercantile Exchange ("NYMEX") less basis) to mitigate the risk of differentials to the Centerpoint East, CIG Hub, Transco Zone 4 and Columbia Gas Transmission (CGTAP) Indexes.

Our financial hedging activities are intended to support natural gas and oil prices at targeted levels and to manage our exposure to natural gas price fluctuations. The counterparty is required to make a payment to us for the difference between the fixed price and the settlement price if the settlement price is below the fixed price. We are required to make a payment to the counterparty for the difference between the fixed price and the settlement price if the fixed price is below the settlement price. These contracts may include financial price swaps whereby we will receive a fixed price for our production and pay a variable market price to the contract counterparty and cashless price collars that set a floor and ceiling price for the hedged production. If the applicable monthly price indices are outside of the ranges set by the floor and ceiling prices in the various collars, we and the counterparty to the collars would be required to settle the difference.

At December 31, 2009 and March 31, 2010, we had in place natural gas swaps covering portions of production from 2010 through 2014. Our senior secured revolving credit facility allows us to hedge up to 85% of our estimated production from proved reserves for up to 12 months in the future, 75% for 13 to 24 months in the future, 65% for 25 to 36 months in the future, 55% for 37 to 48 months in the future and 45% for 49 to 60 months in the future. Based on our annual production and our fixed price swap contracts in place during 2009, our annual income before taxes for the year ended December 31, 2009 would have decreased by approximately $1.0 million for each $0.10 decrease per MMBtu in natural gas prices and approximately $0.1 million for each $1.00 per barrel decrease in crude oil prices.

All derivative instruments, other than those that meet the normal purchase and normal sales exception as mentioned above, are recorded at fair market value in accordance with US GAAP and are included in the consolidated balance sheets as assets or liabilities. Fair values are adjusted for non-performance risk. As required under US GAAP, all fair values are adjusted for non-performance risk. Because we do not designate these hedges as accounting hedges, we do not receive accounting hedge treatment and all mark-to-market gains or losses as well as realized gains or losses on the derivative instruments are recognized in our results of operations. We present realized and unrealized gains or losses on commodity derivatives in our operating revenues as "Realized and unrealized gains (losses) on commodity derivative instruments." In 2009, approximately 72% of our natural gas volumes were hedged, which resulted in realized gains on hedges of $116.5 million. In 2008, approximately 59% of our natural gas volumes were hedged, which resulted in realized gains on hedges of $26.1 million. In 2007, we hedged approximately 81% of our natural gas volumes, which resulted in realized gains on hedges of $14.4 million.

Mark-to-market adjustments of derivative instruments produce earnings volatility but have no cash flow impact relative to changes in market prices until the derivative contracts are settled. We expect continued volatility in the fair value of our derivative instruments. Our cash flow is only impacted when the underlying physical sales transaction takes place in the future and when the associated derivative instrument contract is settled by making or receiving a payment to or from the counterparty. At December 31, 2009, the estimated fair value of our commodity derivative instruments was a net asset of $41.1 million comprised of current and noncurrent assets. At March 31, 2010, the estimated fair value of our commodity derivative instruments was a net asset of $139.9 million comprised of current and noncurrent assets.

The table below summarizes the realized and unrealized gains related to natural gas derivative instruments for years ended December 31, 2007, 2008 and 2009 and the three months ended March 31, 2009 and 2010:

	Year Ended December 31,			Three Months Ended March 31,	
(in thousands)	2007	2008	2009	2009	2010
Realized gains (losses) on commodity derivative contracts	$ 14,373	$ 26,053	$ 116,550	$ 33,572	$ 12,271
Unrealized gains on commodity derivative contracts	4,619	90,301	(61,186)	5,114	98,812
Total	$ 18,992	$ 116,354	$ 55,364	$ 38,686	$ 111,083

As of March 31, 2010, and including swaps entered into since March 31, 2010 through May 14, 2010, we have entered into fixed price natural gas swaps in order to hedge a portion of our natural gas production from 2010 through 2014 as summarized in the following table. Hedge agreements referenced to the Centerpoint, NYMEX and Transco Zone 4 indices are for our production in the Arkoma Basin. Hedge agreements referenced to the CIG index are for our production in the Piceance Basin. Hedge agreements referenced to the CGTAP index are for our production from the Appalachian Basin.

	MMbtu/d	Weighted average index price
Year ending December 31, 2010:		
Centerpoint	30,000	$ 7.20
CIG	30,000	$ 5.12
NYMEX	10,000	$ 6.21
CGTAP	20,000	$ 5.98
Year ending December 31, 2011:		
CIG	35,000	$ 5.78
Transco Zone 4	35,000	$ 6.91
CGTAP	30,000	$ 6.60
Year ending December 31, 2012:		
CIG	35,000	$ 6.06
Transco Zone 4	35,000	$ 7.05
CGTAP	30,000	$ 6.66
Year ending December 31, 2013:		
CIG	40,000	$ 5.93
Transco Zone 4	40,000	$ 6.51
CGTAP	30,000	$ 6.64
Year ending December 31, 2014:		
CIG	40,000	$ 6.07
Transco Zone 4	20,000	$ 6.51
CGTAP	50,000	$ 6.54
Centerpoint	10,000	$ 6.20

By removing price volatility from a portion of our expected natural gas production through December 2014, we have mitigated, but not eliminated, the potential effects of changing prices on our operating cash flow for those periods. While mitigating negative effects of falling commodity prices, these derivative contracts also limit the benefits we would receive from increases in commodity prices.

By using derivative instruments that are not traded on an exchange to hedge exposures to changes in commodity prices, we expose ourselves to the credit risk of our counterparties. Credit risk is the potential failure of the counterparty to perform under the terms of the derivative contract. When the fair value of a derivative contract is positive, the counterparty is expected to owe us, which creates credit risk. To minimize the credit risk in derivative instruments, it is our policy to enter into derivative contracts only with counterparties that are creditworthy financial institutions deemed by management as competent and competitive market makers. The creditworthiness of our counterparties is subject to periodic review. We have economic hedges in place with four different counterparties, of which all but one are lenders in our senior secured revolving credit facility. As of March 31, 2010, derivative positions with JP Morgan, BNP Paribas, Wells Fargo, KeyBank, Union Bank, and Barclays accounted for approximately 54%, 22%, 10%, 8%, 4%, and 2%, respectively, of the net fair value of our commodity derivative assets position. We believe all of these institutions currently are acceptable credit risks. We are not required to provide credit support or collateral to any of our counterparties under current contracts, nor are they required to provide credit support to us. As of December 31, 2009, we have no past due receivables from or payables to any of our counterparties.

Contractual Obligations. A summary of our contractual obligations as of December 31, 2009 is provided in the following table. Our contractual obligations as of March 31, 2010 have not changed significantly from those summarized in the following table.

	As of December 31,						
(in millions)	**2010**	**2011**	**2012**	**2013**	**2014**	**Thereafter**	**Total**
Senior secured revolving credit facility(1)	$ —	$ —	$ 142.1	$ —	$ —	$ —	$ 142.1
Senior notes—interest(2)	35.2	35.2	35.2	35.2	35.2	102.6	278.6
Senior notes—principal(2)	—	—	—	—	—	375.0	375.0
Capital leases	0.2	0.2	0.2	0.2	0.2	0.4	1.4
Drilling rig commitments(3)	9.7	—	—	—	—	—	9.7
Derivative instruments(4)	8.6	2.5	—	—	—	—	11.1
Asset retirement obligations(5)	—	—	—	—	—	3.5	3.5
Office and equipment leases	0.6	0.6	0.3	0.1	—	—	1.6
Total	$ 54.3	$ 38.5	$ 177.8	$ 35.5	$ 35.4	$ 481.5	$ 823.0

(1) Includes outstanding principal amount at December 31, 2009. This table does not include future commitment fees, interest expense or other fees on these facilities because they are floating rate instruments and we cannot determine with accuracy the timing of future loan advances, repayments or future interest rates to be charged.

(2) The 9.375% senior notes are due December 1, 2017.

(3) At December 31, 2009 we had three drilling rigs under contracts which expire in 2010. Any other rig performing work for us is doing so on a well-by-well basis and therefore can be released without penalty at the conclusion of drilling on the current well. Drilling obligations for individual wells have not been included in the table above. The values in the table represent the gross amounts that we are committed to pay. However, we will record in our financial statements our proportionate share based on our working interest.

Drilling rig commitments do not include contingent commitments to drill wells on our unproved properties in order to retain oil and natural gas leasehold interests, including up to an estimated $625 million that we may be required to spend between January 1, 2009 and June 30, 2018 pursuant to the acquisition agreement relating to the purchase of our properties in the Appalachian Basin in 2008.

(4) Derivative instruments represent the fair value for interest rate derivatives presented as liabilities in our combined balance sheet as of December 31, 2009. The ultimate settlement amounts of our derivative liabilities are unknown because they are subject to continuing market fluctuations.

(5) Neither the ultimate settlement amounts nor the timing of our asset retirement obligations can be precisely determined in advance; however, we believe it is likely that a very small amount of these obligations will be settled within the next five years.

In addition to amounts shown in the above table, we have entered into contracts with third party pipeline owners that provide firm processing rights and firm takeaway capacity on pipeline systems. The remaining terms on these contracts range from one to 14 years and require us to pay transportation demand and commodity charges regardless of the amount of pipeline capacity utilized by us.

Critical Accounting Policies and Estimates

The discussion and analysis of our financial condition and results of operations are based upon our consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States. The preparation of our financial statements requires us to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses and related disclosure of contingent assets and liabilities. Certain accounting policies involve judgments and uncertainties to such an extent that there is reasonable likelihood that materially different amounts could have been reported under different conditions, or if different assumptions had been used. We evaluate our estimates and assumptions on a regular basis. We base our estimates on historical experience and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results may differ from these estimates and assumptions used in preparation of our combined financial statements. We provide expanded discussion of our more significant accounting policies, estimates and judgments below. We believe these accounting policies reflect our more significant estimates and assumptions used in preparation of our combined financial statements. See Note 2 of the notes to the audited consolidated financial statements for a discussion of additional accounting policies and estimates made by management.

Natural Gas and Oil Properties

Successful Efforts Method

Our natural gas and oil exploration and production activities are accounted for using the successful efforts method. Under this method, costs of drilling successful exploration wells and development costs are capitalized and amortized on a geological reservoir basis using the unit-of-production method as natural gas and oil is produced. Geological and geophysical costs, delay rentals and costs to drill exploratory wells that do not discover proved reserves are expensed as exploration costs. The costs of development wells are capitalized whether productive or nonproductive. Natural gas and oil lease acquisition costs are also capitalized. The sale of a partial interest in a proved property is accounted for as a cost recovery and no gain or loss is recognized as long as this treatment does not significantly affect the unit-of-production amortization rate. Maintenance and repairs are charged to expense, and renewals and betterments are capitalized to the appropriate property and equipment accounts.

Unproved property costs are costs related to unevaluated properties and are transferred to proved natural gas and oil properties if the properties are determined to be productive. Proceeds from sales of partial interests in unproved leases are accounted for as a recovery of cost without recognizing any gain until all costs are recovered. Unevaluated natural gas and oil properties are assessed periodically for impairment on a property-by-property basis based on remaining lease terms, drilling results, reservoir performance, commodity price outlooks or future plans to develop acreage. If it is determined that it is probable that reserves will not be discovered, the cost of unproved leases is charged to impairment of unproved properties. During the years ended December 31, 2008 and 2009 and the three months ended March 31, 2009 and 2010, we charged impairment expense for expired or expiring leases with a cost of $10.1 million, $54.2 million, $7.8 million and $2.3 million, respectively. The assessment of unevaluated natural gas and oil properties to determine any possible impairment requires managerial judgment.

The successful efforts method of accounting can have a significant impact on the operational results reported when we are entering a new exploratory area in anticipation of finding a gas and oil field that will be the focus of future development drilling activity. The initial exploratory wells may be unsuccessful and will be expensed. Seismic costs can be substantial, which will result in additional exploration expenses when incurred. Additionally, the application of the successful efforts method of accounting requires managerial judgment to determine the proper classification of wells designated as developmental or exploratory, which will ultimately determine the proper accounting treatment of the costs incurred.

Natural Gas and Oil Reserve Quantities and Standardized Measure of Future Cash Flows

Our independent engineers and internal technical staff prepare the estimates of natural gas and oil reserves and associated future net cash flows. Current accounting guidance allows only proved natural gas and oil reserves to be included in our financial statement disclosures. The SEC has defined proved reserves as the estimated quantities of natural gas and oil which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Our independent engineers and internal technical staff must make a number of subjective assumptions based on their professional judgment in developing reserve estimates. Reserve estimates are updated annually and consider recent production levels and other technical information about each field. Natural gas and oil reserve engineering is a subjective process of estimating underground accumulations of natural gas and oil that cannot be precisely measured. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. Periodic revisions to the estimated reserves and future cash flows may be necessary as a result of a number of factors, including reservoir performance, new drilling, natural gas and oil prices, cost changes, technological advances, new geological or geophysical data, or other economic factors. Accordingly, reserve estimates are generally different from the quantities of natural gas and oil that are ultimately recovered. We cannot predict the amounts or timing of future reserve revisions. If such revisions are significant, they could significantly affect future amortization of capitalized costs and result in impairment of assets that may be material.

Impairment of Proved Properties

We review our proved natural gas and oil properties for impairment on a geological reservoir basis whenever events and circumstances indicate that a decline in the recoverability of their carrying value may have occurred. We estimate the expected future cash flows of our gas and oil properties and compare these future cash flows to the carrying amount of the gas and oil properties to determine if the carrying amount is recoverable. If the carrying amount exceeds the estimated undiscounted future cash flows, we will adjust the carrying amount of the natural gas and oil properties to fair value. The factors used to determine fair value are subject to our judgment and expertise and include, but are not limited to, recent sales prices of comparable properties, the present value of future cash flows, net of estimated operating and development costs using estimates of proved reserves, future commodity pricing, future production estimates, anticipated capital expenditures, and various discount rates commensurate with the risk associated with realizing the expected cash flows projected. Because of the uncertainty inherent in these factors, we cannot predict when or if future impairment charges for proved properties will be recorded. We did not record any impairment charges for proved properties during the years ended December 31, 2007, 2008 or 2009 or the three months ended March 31, 2009 and 2010.

New Accounting Pronouncements

SFAS No. 168, The FASB Accounting Codification and the Hierarchy of Generally Accepted Accounting Principles or SFAS 168—In July 2009, the Financial Accounting Standards Board ("FASB") issued SFAS 168 which will establish the Financial Accounting Standards Board Accounting Standards Codification (the "Codification") as the source of authoritative U.S. generally accepted accounting principles ("GAAP") recognized by the FASB to be applied by nongovernmental entities. Rules and interpretive releases issued by the SEC are also sources of authoritative GAAP for SEC registrants.

SFAS No. 160, Noncontrolling Interests in Consolidated Financial Statements, an amendment of Accounting Research Bulletin No. 51 or SFAS 160 codified in FASB ASC Topic 810—In December 2007, the FASB issued SFAS 160, which establishes accounting and reporting standards for ownership interests in subsidiaries held by parties other than the parent, the amount of consolidated net income attributable to the parent and to the noncontrolling interest, changes in a parent's ownership interest and the valuation of retained noncontrolling equity investments when a subsidiary is deconsolidated. SFAS 160 also establishes reporting requirements that provide sufficient disclosures that clearly identify and distinguish between the interests of the parent and the interests of the noncontrolling owners. SFAS 160 is effective for us on January 1, 2009. We have retroactively applied the provisions of this standard in these financial statements. The application of SFAS 160 did not affect our results of operations.

Revised Natural Gas and Oil Standard

In December 2008, the SEC released the final rule for Modernization of Oil and Gas Reporting, or Modernization. The Modernization disclosure requirements require reporting of natural gas and oil reserves using an average price based upon the prior 12 month period rather than year end prices and the use of new technologies to determine proved reserves, if those technologies have been demonstrated to result in reliable conclusions about reserves volumes. Companies are also allowed to disclose probable and possible reserves to investors in SEC filed documents. In addition, companies are required to report the independence and qualifications of their reserves preparer or auditors and file reports when a third party is relied upon to prepare reserves estimates or conduct a reserves audit. The Modernization disclosure requirements have become effective for the year ending December 31, 2009. The FASB has issued Accounting Standards Update 2010-03 (ASU 2010-03) "Extractive Industries—Oil and Gas" to align its rules for oil and gas reserve estimation and disclosure requirements with the SEC's final rule. In October 2009, the SEC issued Staff Accounting Bulletin No. 113 (SAB No. 113), which revises portions of the interpretive guidance included in the section of the Staff Accounting Bulletin Series titled Topic 12: Oil and Gas Producing Activities. The principal changes involve revisions to bring Topic 12 into conformity with the contents of the Modernization. We have adopted the Modernization standard in the preparation of our December 31, 2009 oil and gas reserve estimates and related disclosures.

Quantitative and Qualitative Disclosure about Market Risk

The primary objective of the following information is to provide forward-looking quantitative and qualitative information about our potential exposure to market risk. The term "market risk" refers to the risk of loss arising from adverse changes in natural gas and oil prices and interest rates. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably possible losses. This forward-looking information provides indicators of how we view and manage our ongoing market risk exposures. All of our market risk sensitive instruments were entered into for hedging purposes, rather than for speculative trading.

Commodity Price Risk and Hedges

For a discussion of how we use financial commodity swap contracts to mitigate some of the potential negative impact on our cash flow caused by changes in natural gas prices, see "—Commodity Hedging Activities."

Interest Rate Risks and Hedges

During the year end December 31, 2009, we had indebtedness outstanding under our $400 million senior secured revolving credit facility and $225.0 million under our second lien term loan facility, which bear interest at floating rates. The average annual interest rate incurred on this indebtedness for the years ended December 31, 2009 and 2008 was approximately 4.69% and 6.9%, respectively. A 1.0% increase in each of the average LIBOR rate and federal funds rate for the year ended December 31, 2009 would have resulted in an estimated $5.3 million increase in interest expense for the year ended December 31, 2009 before giving effect to interest rate swaps. During the three months ended March 31, 2010, our indebtedness consisted primarily of fixed rate 9.375% senior notes due 2017 having an outstanding principal amount of $525 million.

Through interest rate derivative contracts, we have attempted to mitigate our exposure to changes in interest rates. We have entered into various variable to fixed interest rate swap agreements which hedge our exposure to interest rate variations on our senior secured revolving credit facility and second lien term loan facility. At March 31, 2010, we had an interest rate swap outstanding for a notional amount of $225 million with a fixed pay rate of 4.11% with a term expiring in July 2011. The $225.0 million swap relates to the floating rate second lien term loan, which was repaid in full with the net proceeds of the November 2009 senior notes offering. We did not terminate the interest rate swap related to the $225.0 million second lien term loan facility when it was repaid in November 2009; therefore, this swap does not currently have floating rate debt associated with it.

Counterparty and Customer Credit Risk

Our principal exposures to credit risk are through receivables resulting from commodity derivatives contracts ($139.9 million at March 31, 2010), joint interest receivables ($4.9 million at March 31, 2010) and the sale of our natural gas production ($22.6 million in receivables at March 31, 2010), which we market to energy marketing companies, refineries and affiliates. Joint interest receivables arise from billing entities who own partial interest in the wells we operate. These entities participate in our wells primarily based on their ownership in leases on which we wish to drill. We can do very little to choose who participates in our wells. We are also subject to credit risk due to concentration of our natural gas receivables with several significant customers. We do not require our customers to post collateral. The inability or failure of our significant customers to meet their obligations to us or their insolvency or liquidation may adversely affect our financial results.

Off-Balance Sheet Arrangements

Currently, we do not have any off-balance sheet arrangements other than operating leases.

BUSINESS

Our Company

Antero Resources is an independent oil and natural gas company engaged in the exploration, development and production of natural gas properties located onshore in the United States. We focus on unconventional reservoirs, which can generally be characterized as fractured shales and tight sand formations. Our properties are primarily located in the Appalachian Basin in West Virginia and Pennsylvania, the Arkoma Basin in Oklahoma and the Piceance Basin in Colorado. Our corporate headquarters are in Denver, Colorado.

Our management team has worked together for many years and has a successful track record of reserve and production growth as well as significant expertise in unconventional resource plays. Our strategy is to leverage our team's experience delineating and developing natural gas resource plays to profitably grow our reserves and production, primarily through internally generated projects on our existing acreage. As of December 31, 2009, our estimated proved reserves were 1,140.7 Bcfe, consisting of 1,130.3 Bcf of natural gas and 1.7 MMBbl of oil and condensate. As of December 31, 2009, 99% of our proved reserves were natural gas, 24% were proved developed and 69% were operated by us. From December 31, 2006 through December 31, 2009, we grew our estimated proved reserves from 87.0 Bcfe to 1,140.7 Bcfe. In addition, we grew our average daily production from 30.8 MMcfe/d for the year ended December 31, 2007 to 105.2 MMcfe/d for the year ended December 31, 2009 and to 117.8 MMcfe/d for the three months ended March 31, 2010. For the year ended December 31, 2009 and the three months ended March 31, 2010, we generated cash flow from operations of $149.3 million and $52.0 million, respectively, net income (loss) of $(106.2) million and $87.6 million, respectively, and EBITDAX of $201.3 million and $51.7 million, respectively. See "Selected Historical Combined Financial Data" for a definition of EBITDAX (a non-GAAP measure) and a reconciliation of EBITDAX to net income (loss).

We have assembled a diversified portfolio of long-lived properties that are characterized by what we believe to be low geologic risk and a large inventory of repeatable drilling opportunities. Our drilling opportunities are focused in the Marcellus Shale of the Appalachian Basin, the Woodford Shale of the Arkoma Basin (the Arkoma Woodford), the Fayetteville Shale of the Arkoma Basin and the Mesaverde tight sands and Mancos Shale of the Piceance Basin. From inception, we have drilled and operated 285 wells through December 31, 2009 with a success rate of approximately 98%. Our drilling inventory consists of approximately 16,000 potential locations, all of which are resource-style opportunities and approximately 9.8% of which are included in our estimated proved reserve base as of December 31, 2009. For information on the possible limitations on our ability to drill our potential locations, see "Risk Factors—Risks Relating to Our Business—Our identified drilling locations are scheduled out over many years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling. In addition, we may not be able to raise the substantial amount of capital that would be necessary to drill a substantial portion of our potential drilling locations."

We own two midstream systems (one in the Arkoma Basin and one in the Piceance Basin), and we believe we have secured sufficient long-term firm takeaway capacity on major pipelines that are in existence or currently under construction in each of our core operating areas to accommodate our existing and foreseeable production.

Our board of directors has approved a capital expenditure budget of up to $366 million for 2010, approximately 89% of which is allocated to drilling. Of our 2010 drilling budget, approximately 43% is allocated to the Appalachian Basin, 29% to the Arkoma Basin Woodford Shale and 28% to the Piceance Basin. Consistent with our historical practice, we periodically review our capital expenditures and adjust our budget based on liquidity, commodity prices and drilling results.

We believe we have a conservative financial position characterized by modest leverage, a strong hedge position and ample liquidity. We have entered into hedging contracts covering a total of approximately 173 Bcf of our natural gas production from April 1, 2010 through December 31, 2014 at a weighted average index price of $6.38 per Mcf. For the nine months ending Deceember 31, 2010, we have hedged approximately 23.6 Bcf of our production at a weighted average index price of $6.13 per Mcf. On November 17, 2009, we completed an offering of $375 million principal amount of our 9.375% senior notes due 2017. On January 19, 2010, we completed an offering of $150 million additional principal amount of our 9.375% senior notes due 2017. On May 12, 2010, the borrowing base under our senior secured revolving credit facility was redetermined at $400 million (the maximum available under the facility). As of such date, after giving effect to the redetermination, we had approximately $361 million of available borrowing capacity under our senior secured revolving credit facility.

Business Strategy

Our objective is to build value through consistent growth in estimated reserves and production on a cost-efficient basis while delineating future drilling locations. Our strategy is to emphasize internally generated drillbit growth on our potential drilling locations in low-risk, repeatable, unconventional resource plays. We have made significant investments in technical staff, acreage and seismic data and technology to build our drilling inventory. Our strategy has the following principal elements:

- *Concentrate on unconventional resources in core operating areas.* We currently operate in three primary basins: the Appalachian Basin in West Virginia and Pennsylvania, the Arkoma Basin in Oklahoma and the Piceance Basin in Colorado. Concentrating our drilling and producing activities on unconventional resources in these core areas allows us to capitalize on the regional expertise that we have developed in interpreting specific geological and operating trends and optimizing drilling and completion techniques. Operating in multiple core areas allows us to optimize capital allocation between basins based on risked well economics to balance our portfolio and achieve consistent and profitable production and reserve growth.

- *Drive growth through low-risk development drilling in established resource plays.* We expect to generate profitable, long-term reserve and production growth predominantly through repeatable, low-risk development drilling on our assets. We typically allocate the substantial majority of our drilling budget to our development and delineation projects. We have a multi-year drilling inventory and have over 16,000 potential drilling locations on our existing leasehold acreage. We have drilled 285 wells from inception through December 31, 2009 and have achieved an approximate 98% success rate.

- *Focus on cost efficiency.* We believe concentrating on our sizeable oil and gas resources in place will allow us to consistently increase production. Our experience suggests that as we increase the density of development within our operating areas, we increase our expected recovery while reducing costs on a per well basis. We endeavor to control costs such that our cost to find, develop and produce natural gas is within the best performing quartile of our peer group based on publicly available information.

- *Maintain financial flexibility and conservative financial position.* We typically use equity capital to fund land acquisitions, exploratory drilling and initial infrastructure, while using cash flow from operations and debt financing to fund our drilling program. We repaid our $225 million second lien term loan facility in full with proceeds from the November 2009 $375 million senior notes offering. In addition, we applied the net proceeds of $124 million from our November 2009 equity placements and applied the balance of the net proceeds from the November senior notes offering and the net proceeds of the January 2010 notes offering to reduce the outstanding balance under our senior secured revolving credit facility. As of May 12, 2010, after giving effect to the redetermination of the borrowing base under our senior secured revolving credit facility at

$400 million, we would have had approximately $361 million of available borrowing capacity under our senior secured revolving credit facility, which, together with our operating cash flow, is expected to provide us with the financial flexibility to pursue our currently planned delineation and development drilling activities.

- *Manage commodity price exposure through an active hedging program.* We maintain an active hedging program designed to mitigate volatility in commodity prices and regional basis differentials. We have entered into hedging contracts covering a total of approximately 173 Bcf of our natural gas production from April 1, 2010 through December 31, 2014 at a weighted average index price of $6.38 per Mcf. For the nine months ending December 31, 2010, we have hedged approximately 23.6 Bcf of our production at a weighted average index price of $6.13 per Mcf. Substantially all of our hedges are at regional sales points in our operating regions, which mitigates the risk of basis differential to the Henry Hub index.

- *Manage midstream assets and secure firm takeaway capacity.* We own midstream systems in the Arkoma Woodford and Piceance Basin, which we believe enhance the efficiency of our drilling operations in those areas. We believe access to gathering and processing infrastructure allows us to decrease dependence on third parties, better manage the timing of our development and optimize the markets to which we sell our production. We expect that our midstream assets will accommodate our anticipated drilling program, resulting in an increase in our throughput volumes and operating cash flows. In addition, we believe we have secured sufficient long-term firm takeaway capacity on major pipelines that are in existence or currently under construction to accommodate our existing and foreseeable production.

Business Strengths

We believe we have the following strengths:

- *Proven track record of efficient production and reserve growth.* We have a proven track record of growth in our production and estimated proved reserves. For example, we grew our production from an average of 30.8 MMcfe/d for the year ended December 31, 2007 to 105.2 MMcfe/d for the year ended December 31, 2009 and to 117.8 MMcfe/d for the three months ended March 31, 2010. In addition, we have grown our estimated proved reserves from 87.0 Bcfe at December 31, 2006 to 1,140.7 Bcfe at December 31, 2009.

- *Multi-year, low-risk, development drilling inventory.* Our drilling inventory consists of approximately 16,000 potential locations, all of which are resource-style opportunities and approximately 9.8% of which are included in our estimated proved reserve base as of December 31, 2009. From inception in 2004 through December 31, 2009, we have drilled and operated 285 wells, achieving an approximate 98% success rate. Our concentrated leasehold position has been delineated largely through drilling done by us as well as other industry players, which we believe will help us to achieve predictable and repeatable future well results and minimize investment risk.

- *Control over operating decisions and capital program.* As of December 31, 2009, we had a net leasehold interest of 61.4% on our acreage and operated 67% of our production. Our high percentage of operated wells allows us to effectively control operating costs, timing of development activities, application of technological enhancements, marketing of production and allocation of our capital budget. In addition, the timing of most of our capital expenditures is discretionary, which allows us a significant degree of flexibility to adjust the size and timing of our development in response to changes in market conditions.

- *Proven executive management team with track record of value creation.* We believe our management team's experience and expertise in the Midcontinent and Rocky Mountain operating regions coupled with our multiple resource plays provides a distinct competitive advantage. Our eight corporate officers have an average of 25 years of industry experience in the Midcontinent and Rocky Mountain operating regions and have successfully built, grown and sold three unconventional resource-focused companies in the past 20 years. Our Chairman and Chief Executive Officer and our President and Chief Financial Officer and many other members of our management team worked together as managers or executives while at Amoco, Barrett Resources, Pennaco Energy, Inc. or Antero Resources Corporation, a former affiliate of our company that operated in the Barnett Shale and was sold to XTO Energy in 2005.

- *Leading technical team with significant unconventional shale and tight sand experience.* All of our proved reserves and resources are classified as unconventional resources, including fractured shale gas plays and basin-centered tight gas. Since 2003, our technical team has drilled and operated over 200 horizontal and over 150 vertical wells in the Barnett, Woodford and Marcellus shales and over 150 directional wells in the Piceance tight sands. Our technical team has significant experience in drilling horizontal and directional wells in addition to fracture stimulation of unconventional formations. We utilize the latest geologic, drilling and completion technologies to increase the predictability and repeatability of finding and recovering resources in these unconventional gas plays. We were an early user of microseismic imaging to monitor frac performance in real time, completed one of the first simul-fracs stimulating three horizontal wells simultaneously in the Barnett Shale and have drilled some of the longest lateral shale gas wells completed to date.

- *Strong sponsor support.* We are backed by a number of well known financial sponsors, including Warburg Pincus, Yorktown Energy Partners and Trilantic Capital Partners. To date, our equity investors have made total equity investments of approximately $1.4 billion, including our November 2009 $125 million equity placements.

Our Operations

Estimated Proved Reserves

The information with respect to our estimated proved reserves presented below has been prepared by our independent reserve engineering firms or by our internal reserve engineers, as applicable, in accordance with the rules and regulations of the SEC applicable to the periods presented. In this prospectus, we have only included estimates of our proved reserves and have not included any estimates of probable or possible reserves that may exist.

New SEC Rules

In December 2008, the SEC adopted new rules related to modernizing reserve calculations and disclosure requirements for oil and natural gas companies, which became effective for annual reporting periods ending on or after December 31, 2009. The most significant amendments to the requirements included the following:

- *Commodity Prices*—Economic producibility of reserves and discounted cash flows are now determined using the unweighted arithmetic average of the first-day-of-the-month commodity prices over the preceding 12-month period unless contractual arrangements designate a different price to be used.

- *Disclosure of Unproved Reserves*—Probable and possible reserves may be disclosed separately on a voluntary basis.

- *Proved Undeveloped Reserve Guidelines*—Reserves may be classified as proved undeveloped if there is a high degree of confidence that the quantities will be recovered and they are scheduled to be drilled within the next five years, unless the specific circumstances justify a longer time.

- *Reserves Estimation Using New Technologies*—Reserves may be estimated through the use of reliable technology in addition to flow tests and production history.

- *Reserves Personnel and Estimation Process*—Additional disclosure is required regarding the qualifications of the chief technical person who oversees the reserves estimation process. We are also required to provide a general discussion of our internal controls used to assure the objectivity of the reserves estimate.

- *Non-Traditional Resources*—The definition of oil and gas producing activities has expanded and focuses on the marketable product rather than the method of extraction.

We adopted these new rules effective December 31, 2009 as required by the SEC.

Application of the new reserve rules resulted in the use of 12-month average prices, which were lower at December 31, 2009 for both oil and gas than the prices we would have used under the previous rules, under which we would have used prices at such date. This resulted in a decrease in some of our proved reserves due to pricing when compared to what our proved reserves would have been at December 31, 2009 using prices at such date. This decrease was offset by our ability to include additional undrilled locations offsetting producing wells in our estimation of our proved reserves under the new rules.

Other Changes to Proved Reserves Presentation

Beginning with the year ended December 31, 2009, we recognized proved reserves from properties having a positive undiscounted net estimated future cash flow as opposed to our practice in prior years of including properties within our proved reserves only if their cash flow was positive using a discount rate of 10% (PV-10). This change is consistent with the SEC definitions of "economic producability" and "proved oil and gas reserves" and consistent with what we believe to be the common practice of the oil and gas industry. Accordingly, the estimated proved reserves as of December 31, 2009 included in this prospectus have been prepared using a different methodology than that used to prepare our estimated proved reserves as of December 31, 2007 and 2008 included in this prospectus. The effect of this change resulted in increased estimated proved reserve volumes as of December 31, 2009 of approximately 138 Bcfe over our estimated proved reserves as of December 31, 2008 and also had the effect of reducing our standardized measure of discounted future net cash flows.

Reserves Presentation

The following table summarizes our estimated proved reserves and related PV-10 at December 31, 2007, 2008 and 2009. All of our proved reserves have been estimated by our independent reserve engineers. Our estimated proved reserves are located in the Appalachian Basin, the Arkoma Basin Woodford Shale, the Piceance Basin and the Fayetteville Shale and are based on reports from Wright & Company, Inc., DeGolyer and MacNaughton ("D&M"), Ryder Scott & Company, L.P. and D&M, respectively. We refer to these firms collectively as our independent engineers. Our independent engineers estimated 100% our our proved reserves in each applicable basin as of December 31, 2009. Copies of the summary reports of our independent engineers with respect to each of our operating basins as of December 31, 2009 are filed as Exhibits 99.1 through 99.4 to the registration statement of which this prospectus forms a part. The information in the following table does not give any effect to or reflect our commodity hedges.

	At December 31,		
	2007	2008	2009
Estimated proved reserves:			
Natural gas (Bcf)	228.7	672.2	1,130.3
Oil and condensate (MMBbl)	1.0	1.2	1.7
Total estimated proved reserves (Bcfe)	234.7	679.6	1,140.7
Proved developed producing (Bcfe)	98.9	238.1	247.0
Proved developed non-producing (Bcfe)	10.2	0.7	28.6
Proved undeveloped (Bcfe)	125.6	440.8	864.9
Percent developed	46.5%	35.1%	24.2%
PV-10 (in millions)(1)	$ 425.9	$ 649.1	$ 244.8
Standardized measure (in millions)(1)	$ 432.1	$ 688.6	$ 235.1

(1) PV-10 was prepared using prices in effect at the end of the periods presented, discounted at 10% per annum, without giving effect to taxes. PV-10 may be considered a non-GAAP financial measure. We believe that the presentation of PV-10 is relevant and useful to our investors as supplemental disclosure to the standardized measure of future net cash flows, or after tax amount, because it presents the discounted future net cash flows attributable to our proved reserves prior to taking into account future corporate income taxes and our current tax structure. While the standardized measure is dependent on the unique tax situation of each company, PV-10 is based on prices and discount factors that are consistent for all companies. Because of this, PV-10 can be used within the industry and by creditors and securities analysts to evaluate estimated net cash flows from proved reserves on a more comparable basis. The difference between the standardized measure and the PV-10 amount is the discounted estimated future income tax.

The following table sets forth the estimated future net cash flows, contracts, from proved reserves (without giving effect to our commodity hedges), the present value of those net cash flows (PV-10), and the prices used in projecting future net cash flows at December 31, 2007, 2008 and 2009:

	At December 31,		
(In millions, except per Mcf data)	2007(1)	2008(2)	2009(3)
Future net cash flows	$ 972.3	$ 1,695.6	$ 1,362
Present value of future net cash flows:			
Before income tax (PV-10)	$ 425.9	$ 649.1	$ 244.8
After income tax (Standardized measure)	$ 432.1	$ 688.6	$ 235.1

(1) Spot prices used at December 31, 2007 were $6.22 per Mcf for the Arkoma Basin and $6.04 per Mcf for the Piceance Basin.

(2) Spot prices used at December 31, 2008 were $4.61 per Mcf for the Arkoma Basin and $4.61 per Mcf for the Piceance Basin.

(3) Average prices used at December 31, 2009 were $3.25 per Mcf for the Arkoma Basin, $3.07 per Mcf for the Piceance Basin and $4.15 per Mcf for the Appalachian Basin.

Future net cash flows represent projected revenues from the sale of proved reserves net of production and development costs (including operating expenses and production taxes). Such calculations for 2007 and 2008 are based on costs and prices in effect at December 31 of each year, without escalation. In accordance with the new SEC rules, prices for 2009 were based on a 12-month average, without escalation. There can be no assurance that the proved reserves will be produced within the periods indicated or that prices and costs will remain constant. There are numerous uncertainties inherent in estimating reserves and related information and different reservoir engineers often arrive at different estimates for the same properties.

Proved Undeveloped Reserves

Our proved undeveloped reserves at December 31, 2009, as estimated by our independent engineers, were 864.9 Bcfe, over 99% of which consisted of natural gas. Changes in proved undeveloped reserves that occurred during the year were due to:

- conversion of 3.2 Bcfe of proved undeveloped reserves into proved developed reserves;
- addition of new proved undeveloped reserves of 754.0 Bcfe, including approximately 138 Bcfe attributable to our decision to recognize proved reserves from properties having a positive undiscounted net estimated future cash flow; and
- negative revision of 326.8 Bcfe in proved undeveloped reserves due to lower commodity prices and performance revisions.

Estimated future development costs relating to the development of our proved undeveloped reserves are approximately $1,389.2 million. All of our proved undeveloped drilling locations are scheduled to be drilled prior to the end of 2014.

Preparation of Reserve Estimates

Our proved reserve estimates as of December 31, 2009 included in this prospectus relating to our properties in the Arkoma Basin Woodford Shale, the Fayetteville Shale, the Piceance Basin and the Appalachian Basin were prepared by our independent engineers in accordance with generally accepted petroleum engineering and evaluation principles and definitions and guidelines established by the SEC. Our independent reserve engineers were selected for their geographic expertise and their historical experience in engineering certain properties. The technical persons at each independent reserve engineering firm responsible for preparing the reserves estimates presented herein meet the requirements regarding qualifications, independence, objectivity and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers.

We maintain an internal staff of petroleum engineers and geoscience professionals who work closely with our independent engineers to ensure the integrity, accuracy and timeliness of data furnished to our independent engineers in their reserves estimation process. Throughout the year, our technical team meets on a regular basis with each independent engineer to review properties and discuss methods and assumptions used by such firms in their respective preparations of our year-end reserves estimates. While we have no formal committee specifically designated to review reserves reporting and the reserves estimation process, preliminary copies of each independent engineer's reserve reports are reviewed by our internal technical staff with representatives of such firms. The independent engineers' reserve estimates and related reports are reviewed and approved by our Vice President of Production, Kevin J. Kilstrom. Mr. Kilstrom has served as Vice President of Production since June 2007. Mr. Kilstrom was a Manager of Petroleum Engineering with AGL Energy of Sydney, Australia from 2006 to 2007. Prior to AGL, Mr. Kilstrom was with Marathon Oil as an Engineering Consultant and Asset Manager from 2003 to 2007 and as a Business Unit Manager for Marathon's Powder River coal bed methane assets from 2001 to 2003. Mr. Kilstrom also served as a member of the board of directors of three Marathon subsidiaries from October 2003 through May 2005. Mr. Kilstrom was an Operations Manager and reserve engineer at Pennaco Energy from 1999 to 2001. Mr. Kilstrom was at Amoco for more than 22 years prior to 1999. Mr. Kilstrom holds a B.S. in Engineering from Iowa State University and an M.B.A. from DePaul University. Our senior management also reviews our independent engineers' reserve estimates and related reports with Mr. Kilstrom and other members of our technical staff. Additionally, our senior management reviews and approves any internally estimated significant changes to our proved reserves on a quarterly basis.

Proved reserves are those quantities of oil and natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations. The term "reasonable certainty" implies a high degree of confidence that the quantities of oil and/or natural gas actually recovered will equal or exceed the estimate. To achieve reasonable certainty, each independent engineer employed technologies that have been demonstrated to yield results with consistency and repeatability. The technologies and economic data used in the estimation of our proved reserves include, but are not limited to, well logs, geologic maps and available downhole and production data, seismic data, well test data.

Production, Revenues and Price History

Natural gas is a commodity. The price that we receive for the natural gas we produce is largely a function of market supply and demand. Demand for natural gas in the United States has increased dramatically during this decade; however, the current economic slowdown reduced this demand during the second half of 2008 and through 2009. Demand is impacted by general economic conditions, weather and other seasonal conditions, including hurricanes and tropical storms. Over or under supply of natural gas can result in substantial price volatility. Historically, commodity prices have been volatile and we expect that volatility to continue in the future. A substantial or extended decline in gas prices or poor drilling results could have a material adverse effect on our financial position, results of operations, cash flows, quantities of gas reserves that may be economically produced and our ability to access capital markets.

The following table sets forth information regarding our production for each field containing 15% or more of our total estimated proved reserves and our total production, and regarding our revenues and realized prices and production costs for the years ended December 31, 2007, 2008 and 2009. For additional information on price calculations, see information set forth in "Management's Discussion and Analysis of Financial Condition and Results of Operations."

	Year Ended December 31,		
	2007	2008	2009
Production data:			
Natural gas (Bcf):			
Arkoma	6.2	18.6	23.4
Piceance	4.7	11.7	11.2
Appalachia	—	—	0.5
Total	10.9	30.3	35.1

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	Year Ended December 31,		
	2007	2008	2009
Oil (MBbl):			
Arkoma	15.3	20.5	26.7
Piceance	34.1	94.4	87.3
Appalachia	—	—	—
Total	49.4	114.9	114.0
NGLs (Bcfe)(1)	—	0.9	2.6
Total combined production (Bcfe)	11.2	31.9	38.4
Daily combined production (MMcfe/d)	30.8	87.4	105.2
Gas and oil production revenues (in millions)	$ 67.7	$ 229.7	$ 129.6
Average prices before effects of hedges (per Mcfe)(2)	$ 6.03	$ 7.41	$ 3.62
Average realized prices after effects of hedges (per Mcfe)(2)	$ 6.65	$ 8.25	$ 6.88
Average costs per Mcfe:			
Lease operating costs	$ 0.39	$ 0.43	$ 0.49
Gathering, compression and transportation	$ 0.89	$ 0.94	$ 0.79
Production taxes	$ 0.20	$ 0.33	$ 0.14
Depreciation, depletion, amortization and accretion	$ 4.46	$ 4.03	$ 3.91
General and administrative	$ 1.04	$ 0.52	$ 0.58

(1) Represents NGLs retained by our midstream business as compensation for processing third-party gas under long term contracts. These amounts are not reflected in the per Mcfe data in this table.

(2) Average prices shown in the table reflect both of the before-and-after effects of our realized commodity hedging transactions. Our calculation of such after-effects includes realized gains or losses on cash settlements for commodity derivatives, which do not qualify for hedge accounting because we do not designate or document them as hedges.

Productive Wells

As of December 31, 2009, we had a total of 792.0 gross (304.0 net) producing wells averaging a 37.8% working interest.

Acreage

The following table sets forth certain information regarding the total developed and undeveloped acreage in which we own an interest as of December 31, 2009. A majority of our developed acreage is subject to mortgage liens securing our revolving credit facility. Acreage related to royalty, overriding royalty and other similar interests is excluded from this table.

Developed Acres		Undeveloped Acres		Total Acres		Percent Leasehold Interest
Gross	Net	Gross	Net	Gross	Net	
132,416	61,796	338,513	227,354	470,929	289,150	61.4%

Undeveloped Acreage Expirations

The following table sets forth the number of total gross and net undeveloped acres as of December 31, 2009 that will expire over the next three years unless production is established within the spacing units covering the acreage prior to the expiration dates or unless such acreage is extended or renewed.

	Gross	Net
2010	82,948	33,122
2011	70,477	26,417
2012	12,806	7,965

Drilling Activity

The following table summarizes our drilling activity for the years ended December 31, 2007, 2008 and 2009. Gross wells reflect the sum of all wells in which we own an interest. Net wells reflect the sum of our working interests in gross wells.

	Year Ended December 31,					
	2007		2008		2009	
	Gross	Net	Gross	Net	Gross	Net
Development wells:						
Productive	36.0	17.5	38.0	25.4	35.0	4.8
Dry	—	—	1.0	0.8	—	—
Total development wells	36.0	17.5	39.0	26.2	35.0	4.8
Exploratory wells:						
Productive	152.0	51.7	297.0	80.1	125.0	19.9
Dry	4.0	1.0	2.0	0.6	1.0	0.08
Total exploratory wells	156.0	52.7	299.0	80.7	126.0	19.98

Our Core Operating Areas

Appalachian Basin Marcellus Shale

Our properties in the Appalachian Basin are principally located in southwest Pennsylvania and northern West Virginia. As of December 31, 2009, we had approximately 119,000 net leasehold acres in the Appalachian Basin, 87% of which was held by production. All of this acreage includes Marcellus Shale rights.

Since spudding our first well in the Appalachian Basin in March 2009, through December 31, 2009 we have completed a total of 4 gross (4 net) horizontal wells and 1 gross (1 net) vertical well in the area. We are currently operating three drilling rigs in the Appalachian Basin. As of December 31, 2009, we had 2,124 potential drilling locations in the area.

Our first two wells in the Marcellus Shale of the Appalachian Basin were brought online in August 2009, and three additional wells were brought online in December 2009.

Approximately 43% of our 2010 drilling budget has been allocated to the Appalachian Basin.

Arkoma Basin Woodford Shale

Our properties in the Arkoma Woodford are located in eastern Oklahoma. As of December 31, 2009, we had approximately 84,000 net leasehold acres in the area, 61% of which was held by production. For the year ended December 31, 2009, we had 60.5 MMcfe/d of average daily production in the area, including NGLs retained by our midstream business.

Our activity in the Arkoma Woodford has consisted of a combination of exploratory, step-out and development drilling designed both to secure acreage and to delineate areas of economic production for further development. As of December 31, 2009, we had a total of 482 gross (122 net) producing wells in the area. We are currently operating one drilling rig in the Arkoma Woodford and, as of December 31, 2009, had 4,693 gross potential drilling locations in the area.

During 2007, we and the industry began to develop this area using alternative spacing to determine the optimum density for development. These results indicate that 80-acre spacing is economically feasible on much of our acreage. In addition, we have reduced our average cost per lateral foot drilled during 2009 through improved mud systems, optimal bit selections, operational efficiencies and reduced drilling day rates. Our development efforts to date have also successfully demonstrated that we are able to drill and complete wells across minor faults that previously limited the length of our lateral drilling.

Approximately 29% of our 2010 drilling budget has been allocated to the Arkoma Basin Woodford Shale.

Piceance Basin

Our properties in the Piceance Basin are located on the western slope of Colorado. As of December 31, 2009, we had approximately 60,000 net leasehold acres in the area.

Since drilling our first well in the Piceance Basin in 2006 and through December 31, 2009, we have operated and completed 185 gross (154.7 net) producing directional wells in the area. For the year ended December 31 2009, we completed 12 gross (6.9 net) directional wells in this area. We had average production of 32.2 MMcfe/d for the year months ended December 31, 2009. We are currently operating one drilling rig and one completion rig in the Piceance Basin and, as of December 31, 2009, had 7,821 potential drilling locations in the area.

We believe we are well positioned to take advantage of the significant opportunities we have identified in the development of the Mesaverde tight sands and the Mancos Shale in the Piceance Basin. We initiated a drilling pilot to evaluate potential Mancos Shale reserves in January 2008. This pilot was designed to test productivity and evaluate the economics of low permeability lithologies of the Mancos/Niobrara petroleum system. We have received formal approval from the Colorado Oil & Gas Commission for 10-acre density for Mancos/Niobrara on 7,000 acres. We also received approval to commingle our Mancos Shale production with production from the overlying Mesaverde tight sand formation, which we believe will enhance our economic returns in this area.

Approximately 28% of our 2010 drilling budget has been allocated to the Piceance Basin.

Other Operating Areas

Fayetteville Shale

As of December 31, 2009, we held approximately 6,000 net acres in the eastern part of the Fayetteville Shale. We had average production of 4.0 MMcfe/d for the year ended December 31, 2009. We have 83 gross (5.3 net) wells currently on production. We do not operate wells in the Fayetteville Shale but participate in wells operated by others.

Our Midstream Operations

Arkoma Midstream System

We own 60% of Centrahoma Processing LLC, a joint venture that operates two cryogenic processing plants in the Arkoma Basin. The remaining 40% interest in Centrahoma is owned by MarkWest. These plants are currently running at or near their operational capacity of 100 MMcf/d, yield 8,000 to 9,000 gross Bbl/d of NGLs and are capable of yielding NGLs of up to 4.0 gallons per Mcf. Due to capacity constraints at these plants, we are in the early stages of a plant capacity expansion plan for 2011. All of our and the majority of Newfield Exploration's wet gas in the Woodford Play is processed at these plants under long term contracts. In addition, the ONEOK NGL pipeline, which both of our plants deliver NGL products into, became operational in September 2008.

We own and operate an amine treating plant for CO_2 removal in the East Rockpile area of the Arkoma Woodford. This plant is located in one of our key drilling areas, has 42 MMcf/d capacity and is currently running at 25 MMcf/d.

We also own approximately 50 miles of gathering pipeline in the Northern Front and East Rockpile areas of the Arkoma Woodford.

In April 2010, we began a process to consider a sale of our Arkoma Woodford midstream assets. We have not yet entered into a definitive agreement with respect to this sale, and we cannot be certain that any definitive agreement will be entered into or that any sale transaction will be consummated.

Piceance Gathering System

We own approximately 20 miles of gathering pipeline in the Gravel Trend in the Piceance Basin. We do not currently own or operate any compression facilities in the area. Our gas is gathered and delivered to third parties for compression, processing and takeaway.

Takeaway Capacity

Arkoma Basin

We currently have firm takeaway capacity of 20 MMcf/d on the Ozark Gas Transmission Pipeline through August 2012 and 20 MMcf/d of firm takeaway capacity on the Boardwalk Gulf Crossing Pipeline through July 2014. We have also contracted for 10 MMcf/d of additional takeaway capacity on the Boardwalk Gulf Crossing Pipeline to begin in August 2010 and another 10 MMcf/d of additional takeaway capacity to begin in August 2011, with both contracts having five-year terms.

Piceance Basin

We currently have 40MMcf/d of firm takeaway capacity on the WIC Pipeline through September 2020. The El Paso WIC Pipeline expansion from Meeker, Colorado to Opal, Wyoming will provide 230 MMcf/d of incremental capacity to more liquid markets. Additionally, we have contracted for 25 MMcf/d of firm takeaway capacity for 10 years on the El Paso Ruby Pipeline that has applied to FERC for authorization to commence construction. The Ruby Pipeline will begin in Opal, Wyoming and is expected to provide approximately 1.3 Bcf/d of incremental pipeline capacity to the Northwest and West Coast of the United States beginning in 2011.

Appalachian Basin

We have 40 MMcf/d of firm transportation on the Columbia Pipeline from August 2009 for 7.5 years. In April 2010, we added an additional 110 MMcf/d of firm transportation capacity on the Columbia Pipeline, of which 70 MMcf/d is scheduled to begin in August 2010 and the remaining

40 MMcf/d is scheduled to begin in April 2011. Our contract for this additional capacity runs through March 2021.

Corporate Sponsorship and Structure

We began operations in 2004, and have funded development and operating activities of each of the operating subsidiaries primarily through equity capital raised from private equity sponsors and institutional investors, through borrowings under our bank credit facilities and through internal operating cash flows. Our primary private equity sponsors are affiliates of Warburg Pincus, Yorktown Energy Partners and Trilantic Capital Partners.

Antero Resources LLC was formed as a holding company in October 2009 in connection with our November 2009 corporate reorganization of the operating subsidiaries and the issuance of a new class of units. Prior to this reorganization, all of our operations were conducted by five separately capitalized commonly controlled operating subsidiaries.

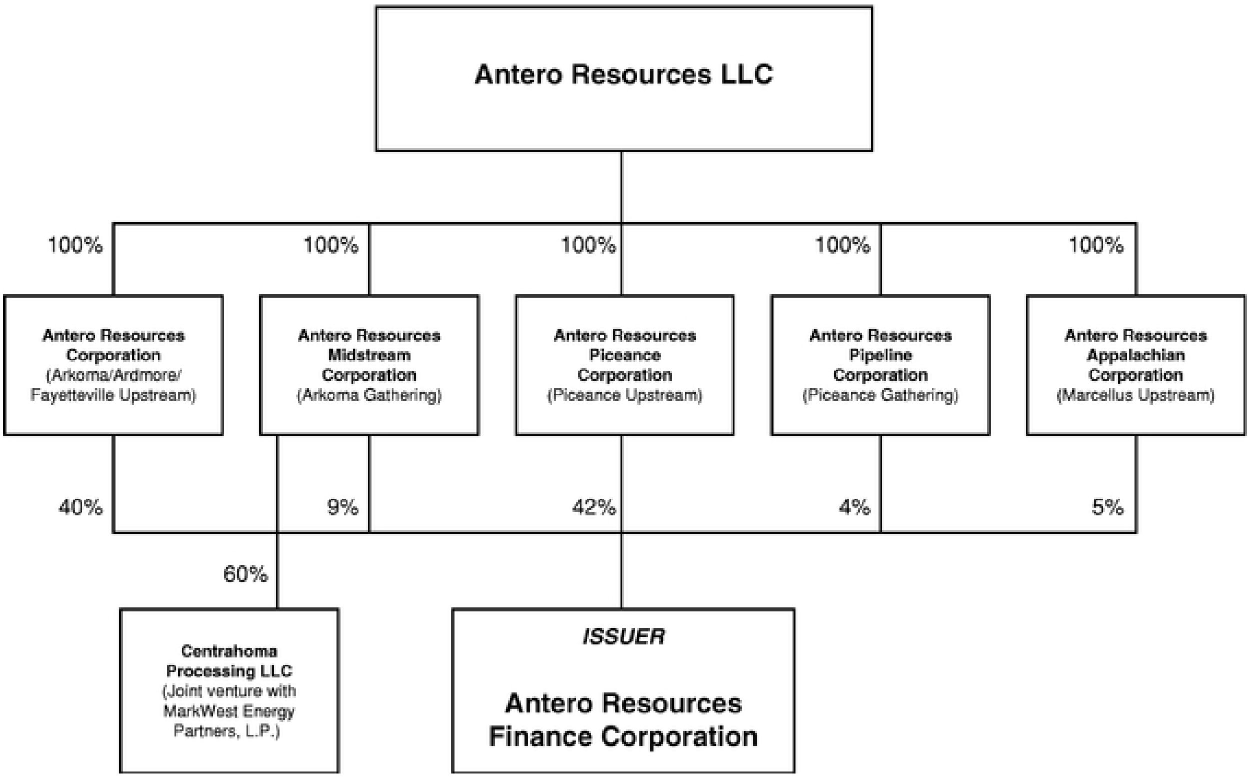
In connection with the November 2009 corporate reorganization, the stockholders of each of the operating subsidiaries contributed all of the outstanding shares of each operating subsidiary to Antero. In return, Antero issued an equivalent number of units of different classes to such stockholders. The newly issued units are substantially similar in character to the contributed stock of each operating subsidiary, including the relative priority of any distributions made by Antero as well as the vesting schedule applicable to shares held by any member of management. Simultaneously with this exchange, Antero issued a new class of units in exchange for $110 million in new equity capital. Later in November 2009, Antero issued additional units of such new class in exchange for an additional $15 million in new equity capital.

None of Antero's outstanding units are entitled to current cash distributions or are convertible into indebtedness, and Antero has no obligation to repurchase these units at the election of the unitholders. Although Antero is required to make quarterly distributions to cover any income taxes allocated to each unitholder, the unitholders have no other rights to cash distributions (except in the case of certain liquidation events). We do not anticipate making any such tax distributions in the foreseeable future. Pursuant to the terms of Antero's limited liability company agreement, upon certain liquidation events, units held by our private equity sponsors and institutional investors are entitled to receive, prior to any amounts received by other unitholders, an amount equal to the initial purchase price of such units plus a special distribution with respect to such units and will continue to participate on a pro rata basis with other unitholders in any excess funds available in liquidation. For more information on the terms of the Antero limited liability company agreement, see "Management—Certain Relationships and Related Party Transactions."

Concurrent with the closing of the reorganization, Antero issued profits interests to Antero Resources Employee Trust, LLC, a newly formed Delaware limited liability company, owned solely by certain of our officers and employees. These profits interests only participate in distributions upon liquidation events meeting certain requisite financial return thresholds. In turn, Antero Resources Employee Trust issued similar profits interests to certain of our officers and employees.

We used the aggregate net proceeds of approximately $124 million from the November 2009 equity placements to repay borrowings outstanding under our senior secured revolving credit facility.

The following diagram shows our organizational structure after giving effect to the November 2009 corporate reorganization:



The issuer was formed in October 2009 as an indirect wholly owned subsidiary of Antero. The issuer was formed to arrange financing for Antero and the operating subsidiaries, including the notes offered hereby. The indenture governing the notes limits the issuer's activity to those of a finance subsidiary. The issuer does not own any significant assets other than intercompany obligations.

The payment of the principal, premium and interest on the notes is fully and unconditionally guaranteed on a senior unsecured basis by Antero Resources LLC, all of its wholly owned subsidiaries (other than the issuer) and certain of its future restricted subsidiaries. Centrahoma Processing LLC is a joint venture owned 60% by Antero and 40% by MarkWest Energy Partners, L.P. and does not guarantee the notes. As of March 31, 2010, Centrahoma Processing LLC, had no outstanding indebtedness and held less than 4% of our consolidated total assets. The guarantees are unsecured senior indebtedness of the guarantors and have the same ranking with respect to the guarantors' indebtedness as the notes have with respect to the issuer's indebtedness. See "Description of Notes—Guarantees."

Marketing and Major Customers

We market the majority of the natural gas production from properties we operate for both our account and the account of the other working interest owners in these properties. We sell substantially all of our production to a variety of purchasers under short-term contracts or spot gas purchase contracts ranging anywhere from one day to seven months, all at market prices. We normally sell production to a relatively small number of customers, as is customary in the exploration, development and production business. However, based on the current demand for natural gas and oil and availability of other purchasers, we believe that the loss of any one or all of our major purchasers would not have a material adverse effect on our financial condition and results of operations. For a list of our customers that accounted for 10% or more of our natural gas revenues during the last two calendar years, see "Note 2(p)—Concentrations of Credit Risk" in our audited consolidated financial statements for the years ended December 31, 2009, 2008 and 2007 included elsewhere in this prospectus.

Title to Properties

We believe that we have satisfactory title to all of our producing properties in accordance with generally accepted industry standards. As is customary in the industry, in the case of undeveloped properties, often cursory investigation of record title is made at the time of lease acquisition. Investigations are made before the consummation of an acquisition of producing properties and before commencement of drilling operations on undeveloped properties. Individual properties may be subject to burdens that we believe do not materially interfere with the use or affect the value of the properties. Burdens on properties may include:

- customary royalty interests;
- liens incident to operating agreements and for current taxes;
- obligations or duties under applicable laws;
- development obligations under natural gas leases; or
- net profits interests.

In addition, the acquisition agreement relating to the purchase of our properties in the Appalachian Basin in 2008 contains various drilling commitments that may require us to spend up to an estimated $625 million between January 1, 2009 and June 30, 2018 at structured intervals. If we do not fulfill our drilling commitments, title to portions of the properties we purchased may revert to the seller, which could have a material adverse effect on our future business and results of operations.

Seasonality

Demand for natural gas generally decreases during the spring and fall months and increases during the summer and winter months. However, seasonal anomalies such as mild winters or mild summers sometimes lessen this fluctuation. In addition, certain natural gas users utilize natural gas storage facilities and purchase some of their anticipated winter requirements during the summer. This can also lessen seasonal demand fluctuations. Seasonal weather conditions and lease stipulations can limit our drilling and producing activities and other natural gas operations in certain areas of the Rocky Mountain region. These seasonal anomalies can increase competition for equipment, supplies and personnel during the spring and summer months, which could lead to shortages and increase costs or delay our operations.

Competition

The oil and natural gas industry is intensely competitive, and we compete with other companies in our industry that have greater resources than we do. Many of these companies not only explore for and produce natural gas, but also carry on refining operations and market petroleum and other products on a regional, national or worldwide basis. These companies may be able to pay more for productive natural gas properties and exploratory prospects or define, evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit and may be able to expend greater resources to attract and maintain industry personnel. In addition, these companies may have a greater ability to continue exploration activities during periods of low natural gas market prices. Our larger competitors may be able to absorb the burden of existing, and any changes to, federal, state and local laws and regulations more easily than we can, which would adversely affect our competitive position. Our ability to acquire additional properties and to discover reserves in the future will be dependent upon our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. In addition, because we have fewer financial and human resources than many companies in our industry, we may be at a disadvantage in bidding for exploratory prospects and producing natural gas properties.

Regulation of the Natural Gas and Oil Industry

Our operations are substantially affected by federal, state and local laws and regulations. In particular, natural gas production and related operations are, or have been, subject to price controls, taxes and numerous other laws and regulations. All of the jurisdictions in which we own or operate producing natural gas and oil properties have statutory provisions regulating the exploration for and production of natural gas and oil, including provisions related to permits for the drilling of wells, bonding requirements to drill or operate wells, the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, sourcing and disposal of water used in the drilling and completion process, and the abandonment of wells. Our operations are also subject to various conservation laws and regulations. These include the regulation of the size of drilling and spacing units or proration units, the number of wells which may be drilled in an area, and the unitization or pooling of crude natural gas wells, as well as regulations that generally prohibit the venting or flaring of natural gas, and impose certain requirements regarding the ratability or fair apportionment of production from fields and individual wells.

Failure to comply with applicable laws and regulations can result in substantial penalties. The regulatory burden on the industry increases the cost of doing business and affects profitability. Although we believe we are in substantial compliance with all applicable laws and regulations, such laws and regulations are frequently amended or reinterpreted. Therefore, we are unable to predict the future costs or impact of compliance. Additional proposals and proceedings that affect the natural gas industry are regularly considered by Congress, the states, the Federal Energy Regulatory Commission ("FERC"), and the courts. We cannot predict when or whether any such proposals may become effective.

We believe we are in substantial compliance with currently applicable laws and regulations and that continued substantial compliance with existing requirements will not have a material adverse effect on our financial position, cash flows or results of operations. However, current regulatory requirements may change, currently unforeseen environmental incidents may occur or past non-compliance with environmental laws or regulations may be discovered.

Regulation of Production of Natural Gas and Oil

The production of natural gas and oil is subject to regulation under a wide range of local, state and federal statutes, rules, orders and regulations. Federal, state and local statutes and regulations require permits for drilling operations, drilling bonds and reports concerning operations. All of the states in which we own and operate properties have regulations governing conservation matters, including provisions for the unitization or pooling of natural gas and oil properties, the establishment of maximum allowable rates of production from natural gas and oil wells, the regulation of well spacing, and plugging and abandonment of wells. The effect of these regulations is to limit the amount of natural gas and oil that we can produce from our wells and to limit the number of wells or the locations at which we can drill, although we can apply for exceptions to such regulations or to have reductions in well spacing. Moreover, each state generally imposes a production or severance tax with respect to the production and sale of oil, natural gas and natural gas liquids within its jurisdiction.

We own interests in properties located onshore in a number of U.S. states. These states regulate drilling and operating activities by requiring, among other things, permits for the drilling of wells, maintaining bonding requirements in order to drill or operate wells, and regulating the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled and the plugging and abandonment of wells. The laws of these states also govern a number of environmental and conservation matters, including the handling and disposing or discharge of waste materials, the size of drilling and spacing units or proration units and the density of wells that may be drilled, unitization and pooling of oil and gas properties and establishment of maximum rates of production from oil and gas wells. Some states have the power to prorate production to the market demand for oil and gas.

The failure to comply with these rules and regulations can result in substantial penalties. Our competitors in the natural gas and oil industry are subject to the same regulatory requirements and restrictions that affect our operations.

Regulation of Transportation and Sales of Natural Gas

Historically, the transportation and sale for resale of natural gas in interstate commerce have been regulated by agencies of the U.S. federal government, primarily FERC. FERC regulates interstate natural gas transportation rates and service conditions, which affects the marketing of natural gas that we produce, as well as the revenues we receive for sales of our natural gas. Since 1985, FERC has endeavored to make natural gas transportation more accessible to natural gas buyers and sellers on an open and non-discriminatory basis. FERC has stated that open access policies are necessary to improve the competitive structure of the interstate natural gas pipeline industry and to create a regulatory framework that will put natural gas sellers into more direct contractual relations with natural gas buyers by, among other things, unbundling the sale of natural gas from the sale of transportation and storage services.

In the past, the federal government has regulated the prices at which natural gas could be sold. While sales by producers of natural gas can currently be made at uncontrolled market prices, Congress could reenact price controls in the future. Deregulation of wellhead natural gas sales began with the enactment of the Natural Gas Policy Act ("NGPA") and culminated in adoption of the Natural Gas Wellhead Decontrol Act which removed controls affecting wellhead sales of natural gas effective January 1, 1993. The transportation and sale for resale of natural gas in interstate commerce is regulated primarily under the Natural Gas Act ("NGA") and by regulations and orders promulgated under the NGA by FERC. In certain limited circumstances, intrastate transportation and wholesale sales of natural gas may also be affected directly or indirectly by laws enacted by Congress and by FERC regulations.

Beginning in 1992, FERC issued a series of orders to implement its open access policies. As a result, the interstate pipelines' traditional role as wholesalers of natural gas has been eliminated and replaced by a structure under which pipelines provide transportation and storage service on an open access basis to others who buy and sell natural gas. Although FERC's orders do not directly regulate natural gas producers, they are intended to foster increased competition within all phases of the natural gas industry.

The Domenici-Barton Energy Policy Act of 2005 ("EP Act 2005") is a comprehensive compilation of tax incentives, authorized appropriations for grants and guaranteed loans, and significant changes to the statutory policy that affects all segments of the energy industry. Among other matters, EP Act 2005 amends the NGA to add an anti-market manipulation provision which makes it unlawful for any entity to engage in prohibited behavior to be prescribed by FERC, and furthermore provides FERC with additional civil penalty authority. The EP Act 2005 provides FERC with the power to assess civil penalties of up to $1,000,000 per day for violations of the NGA and increases FERC's civil penalty authority under the NGPA from $5,000 per violation per day to $1,000,000 per violation per day. The civil penalty provisions are applicable to entities that engage in the sale of natural gas for resale in interstate commerce. On January 19, 2006, FERC issued Order No. 670, a rule implementing the anti-market manipulation provision of EP Act 2005, and subsequently denied rehearing. The rules make it unlawful to: (1) in connection with the purchase or sale of natural gas subject to the jurisdiction of FERC, or the purchase or sale of transportation services subject to the jurisdiction of FERC, for any entity, directly or indirectly, to use or employ any device, scheme or artifice to defraud; (2) to make any untrue statement of material fact or omit to make any such statement necessary to make the statements made not misleading; or (3) to engage in any act or practice that operates as a fraud or deceit upon any person. The new anti-market manipulation rule does not apply to activities that relate only to intrastate or other non-jurisdictional sales or gathering, but does apply to activities of gas pipelines and storage companies that provide interstate services, as well as otherwise non-jurisdictional entities to the extent the activities are conducted "in connection with" gas sales, purchases or transportation subject to FERC jurisdiction, which now includes the annual reporting requirements under Order 704. The anti-market manipulation rule and enhanced civil penalty authority reflect an expansion of FERC's NGA enforcement authority.

On December 26, 2007, FERC issued Order 704, a final rule on the annual natural gas transaction reporting requirements, as amended by subsequent orders on rehearing. Under Order 704, wholesale buyers and sellers of more than 2.2 million MMBtus of physical natural gas in the previous calendar year, including natural gas gatherers and marketers, are now required to report, on May 1 of each year beginning in 2009, aggregate volumes of natural gas purchased or sold at wholesale in the prior calendar year to the extent such transactions utilize, contribute to, or may contribute to the formation of price indices. It is the responsibility of the reporting entity to determine which individual transactions should be reported based on the guidance of Order 704. Order 704 also requires market participants to indicate whether they report prices to any index publishers, and if so, whether their reporting complies with FERC's policy statement on price reporting.

On November 20, 2008, FERC issued Order 720, a final rule on the daily scheduled flow and capacity posting requirements. Under Order 720, major non-interstate pipelines, defined as certain non-interstate pipelines delivering, on an annual basis, more than an average of 50 million MMBtus of gas over the previous three calendar years, are required to post daily certain information regarding the pipeline's capacity and scheduled flows for each receipt and delivery point that has a design capacity equal to or greater than 15,000 MMBtu per day. Requests for clarification and rehearing of Order 720 have been filed at FERC and a decision on those requests is pending.

We cannot accurately predict whether FERC's actions will achieve the goal of increasing competition in markets in which our natural gas is sold. Additional proposals and proceedings that might affect the natural gas industry are pending before FERC and the courts. The natural gas industry historically has been very heavily regulated. Therefore, we cannot provide any assurance that the less stringent regulatory approach recently established by FERC will continue. However, we do not believe that any action taken will affect us in a way that materially differs from the way it affects other natural gas producers.

Gathering service, which occurs upstream of jurisdictional transmission services, is regulated by the states onshore and in state waters. Although its policy is still in flux, FERC has reclassified certain jurisdictional transmission facilities as non-jurisdictional gathering facilities, which has the tendency to increase our costs of getting gas to point of sale locations. State regulation of natural gas gathering facilities generally include various safety, environmental and, in some circumstances, nondiscriminatory-take requirements. Although such regulation has not generally been affirmatively applied by state agencies, natural gas gathering may receive greater regulatory scrutiny in the future.

Section 1(b) of the NGA exempts natural gas gathering facilities from regulation by FERC as a natural gas company under the NGA. We believe that the natural gas pipelines in our gathering systems meet the traditional tests FERC has used to establish a pipeline's status as a gatherer not subject to regulation as a natural gas company. However, the distinction between FERC-regulated transmission services and federally unregulated gathering services is the subject of on-going litigation, so the classification and regulation of our gathering facilities are subject to change based on future determinations by FERC, the courts or Congress.

Our sales of natural gas are also subject to requirements under the Commodity Exchange Act ("CEA") and regulations promulgated thereunder by the Commodity Futures Trading Commission ("CFTC"). The CEA prohibits any person from manipulating or attempting to manipulate the price of any commodity in interstate commerce or futures on such commodity. The CEA also prohibits knowingly delivering or causing to be delivered false or misleading or knowingly inaccurate reports concerning market information or conditions that affect or tend to affect the price of a commodity.

Intrastate natural gas transportation is also subject to regulation by state regulatory agencies. The basis for intrastate regulation of natural gas transportation and the degree of regulatory oversight and scrutiny given to intrastate natural gas pipeline rates and services varies from state to state. Insofar as such regulation within a particular state will generally affect all intrastate natural gas shippers within the state on a comparable basis, we believe that the regulation of similarly situated intrastate natural gas transportation in any states in which we operate and ship natural gas on an intrastate basis will not affect our operations in any way that is of material difference from those of our competitors. Like the regulation of interstate transportation rates, the regulation of intrastate transportation rates affects the marketing of natural gas that we produce, as well as the revenues we receive for sales of our natural gas.

Changes in law and to FERC policies and regulations may adversely affect the availability and reliability of firm and/or interruptible transportation service on interstate pipelines, and we cannot predict what future action FERC will take. We do not believe, however, that any regulatory changes will affect us in a way that materially differs from the way they will affect other natural gas producers, gatherers and marketers with which we compete.

Regulation of Environmental and Occupational Matters

Our operations are subject to numerous stringent federal, state and local statutes and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection, some of which carry substantial administrative, civil and criminal penalties for failure to comply. These laws and regulations may require the acquisition of a permit before drilling commences, restrict the types, quantities and concentrations of various substances that can be released into the environment in connection with drilling, production and transporting through pipelines, govern the sourcing and disposal of water used in the drilling and completion process, limit or prohibit drilling activities in certain areas and on certain lands lying within wilderness, wetlands, frontier and other protected areas, require some form of remedial action to prevent or mitigate pollution from former operations such as plugging abandoned wells or closing earthen pits and impose substantial liabilities for pollution resulting from operations or failure to comply with regulatory filings. In addition, these laws and regulations may restrict the rate of production.

National Environmental Policy Act

Natural gas and oil exploration and production activities on federal lands are subject to the National Environmental Policy Act, or NEPA. NEPA requires federal agencies, including the Departments of Interior and Agriculture, to evaluate major agency actions having the potential to significantly impact the environment. In the course of such evaluations, an agency prepares an environmental assessment to evaluate the potential direct, indirect and cumulative impacts of a proposed project. If impacts are considered significant, the agency will prepare a more detailed environmental impact study ("EIS") that is made available for public review and comment. All of our current exploration and production activities, as well as proposed exploration and development plans, on federal lands require governmental permits that are subject to the requirements of NEPA. This environmental impact assessment process has the potential to delay the development of natural gas and oil projects. Authorizations under NEPA also are subject to protest, appeal or litigation, which can delay or halt projects.

Waste Handling

We also may incur liability under the Resource Conservation and Recovery Act, as amended ("RCRA"), which imposes requirements related to the generation, transportation, treatment, storage, handling, disposal and clean-up of solid and hazardous wastes and the disposal of non-hazardous wastes. Under the auspices of the Environmental Protection Agency, or the EPA, the individual states administer some or all of the provisions of RCRA, sometimes in conjunction with their own, more stringent requirements. Drilling fluids, produced waters and most of the other wastes associated with the exploration, development and production of crude oil, natural gas, or geothermal energy constitute "solid wastes," which are regulated under the less stringent, non-hazardous waste provisions, but there is no guarantee that the EPA or the individual states will not adopt more stringent requirements for the handling of non-hazardous wastes or categorize some non-hazardous wastes as hazardous for future regulation. Indeed, legislation has been proposed from time to time in Congress to re-categorize certain oil and gas exploration and production wastes as "hazardous wastes."

We believe that we are in substantial compliance with the requirements of RCRA and related state and local laws and regulations, and that we held all necessary and up-to-date permits, registrations and other authorizations to the extent that our operations require them under such laws and regulations. Although we believe that the current costs of managing our wastes as they are presently classified are reflected in our budget, any legislative or regulatory reclassification of natural gas and oil exploration and production wastes could increase our costs to manage and dispose of such wastes.

Water Discharges

The Federal Water Pollution Control Act, as amended, also known as the Clean Water Act, and comparable state laws impose restrictions and strict controls regarding the discharge of pollutants, including produced waters and other natural gas wastes, into federal and state waters. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or the state. The discharge of dredge and fill material in regulated waters, including wetlands, is also prohibited, unless authorized by a permit issued by the U.S. Army Corps of Engineers. Obtaining permits has the potential to delay the development of natural gas and oil projects. These same regulatory programs also limit the total volume of water that can be discharged, hence limiting the rate of development. These laws and any implementing regulations provide for administrative, civil and criminal penalties for any unauthorized discharges of oil and other substances in reportable quantities and may impose substantial potential liability for the costs of removal, remediation and damages.

Pursuant to these laws and regulations, we may be required to obtain and maintain approvals or permits for the discharge of wastewater or storm water and are required to develop and implement spill prevention, control and countermeasure plans, also referred to as "SPCC plans," in connection with on-site storage of significant quantities of oil. We maintain all required discharge permits necessary to conduct our operations, and we believe we are in substantial compliance with the terms thereof. We are currently undertaking a review of recently acquired natural gas properties to determine the need for new or updated SPCC plans and, where necessary, we will be developing or upgrading such plans, the costs of which are not expected to be substantial.

Air Emissions

The Federal Clean Air Act, as amended, and comparable state laws restrict the emission of air pollutants from many sources, including compressor stations, through the issuance of permits and the imposition of other requirements. In addition, the EPA has developed, and continues to develop, stringent regulations governing emissions of toxic air pollutants at specified sources. These laws and any implementing regulations may require us to obtain pre-approval for the construction or modification of certain projects or facilities expected to produce air emissions, impose stringent air permit requirements, or use specific equipment or technologies to control emissions.

While we may be required to incur certain capital expenditures in the next few years for air pollution control equipment in connection with maintaining or obtaining operating permits addressing other air emission-related issues, we do not believe that such requirements will have a material adverse effect on our operations. Obtaining permits has the potential to delay the development of natural gas and oil projects. We believe that we are in substantial compliance with all air emissions regulations and that we hold all necessary and valid construction and operating permits for our operations.

Regulation of "Greenhouse Gas" Emissions

Recent scientific studies have suggested that emissions of certain gases, commonly referred to as "greenhouse gases" (GHGs) and including carbon dioxide and methane, may be contributing to warming of the Earth's atmosphere and other climatic changes. In response to such studies, the U.S. Congress is actively considering legislation to reduce emissions of GHGs. One bill approved by the U.S. House of Representatives in June 2009, known as the American Clean Energy and Security Act of 2009, or ACESA, would require an 80% reduction in emissions of GHGs from sources within the U.S. between 2012 and 2050. Similar bills are presently pending before the U.S. Senate. Moreover, almost half of the states have already taken legal measures to reduce emissions of GHGs, primarily through the planned development of GHG emission inventories and/or regional GHG cap and trade programs. Most of these cap and trade programs work by requiring major sources of emissions, such as electric power plants, or major producers of fuels, such as refineries and gas processing plants, to acquire and surrender emission allowances. The number of allowances available for purchase is reduced each year until the overall GHG emission reduction goal is achieved.

In addition, in December 2009, the U.S. Environmental Protection Agency, or the EPA, determined that emissions of carbon dioxide, methane and other GHGs present an endangerment to human health and the environment, because emissions of such gases are, according to the EPA, contributing to warming of the earth's atmosphere and other climatic changes. These findings by the EPA allow the agency to proceed with the adoption and implementation of regulations that would restrict emissions of GHGs under existing provisions of the federal Clean Air Act. In response to its endangerment finding, the EPA recently adopted two sets of rules regarding possible future regulation of GHG emissions under the Clean Air Act, one of which purports to regulate emissions of GHGs from motor vehicles and the other of which would regulate emissions of GHGs from large stationary sources of emissions such as power plants or industrial facilities. The motor vehicle rule became effective in March 2010 but it does not require immediate reductions in GHG emissions. The stationary source rule was adopted in May 2010 but it does not become effective until January 2011 and is the subject of several pending lawsuits filed by industry groups. Additionally, in September 2009, the EPA issued a final rule requiring the reporting of GHG emissions from specified large GHG emission sources in the U.S., including natural gas liquids fractionators and local natural gas/distribution companies, beginning in 2011 for emissions occurring in 2010.

The adoption of legislation or regulatory programs to reduce emissions of GHGs could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emissions allowances or comply with new regulatory requirements. Any such legislation or regulatory programs could also increase the cost of consuming, and thereby reduce demand for, the oil and natural gas we produced. Consequently, legislation and regulatory programs to reduce emissions of GHGs could have an adverse effect on our business, financial condition and results of operations.

Occupational Safety and Health Act

We are also subject to the requirements of the federal Occupational Safety and Health Act, as amended ("OSHA"), and comparable state laws that regulate the protection of the health and safety of employees. In addition, OSHA's hazard communication standard requires that information be maintained about hazardous materials used or produced in our operations and that this information be provided to employees, state and local government authorities and citizens. We believe that our operations are in substantial compliance with the OSHA requirements.

Endangered Species Act

The Endangered Species Act ("ESA") was established to protect endangered and threatened species. Pursuant to the ESA, if a species is listed as threatened or endangered, restrictions may be imposed on activities adversely affecting that species' habitat. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act. We conduct operations on federal natural gas and oil leases in areas where certain species that are listed as threatened or endangered and where other species, such as the sage grouse, potentially could be listed as threatened or endangered under the ESA exist. The U.S. Fish and Wildlife Service may designate critical habitat and suitable habitat areas that it believes are necessary for survival of a threatened or endangered species. A critical habitat or suitable habitat designation could result in further material restrictions to federal land use and may materially delay or prohibit land access for natural gas and oil development. If we were to have a portion of our leases designated as critical or suitable habitat, it could adversely impact the value of our leases.

In summary, we believe we are in substantial compliance with currently applicable environmental laws and regulations. Although we have not experienced any material adverse effect from compliance with environmental requirements, there is no assurance that this will continue. We did not have any material capital or other non-recurring expenditures in connection with complying with environmental laws or environmental remediation matters in 2009, nor do we anticipate that such expenditures will be material in 2010.

Legal Matters

We are a named defendant in certain lawsuits arising in the ordinary course of business. While the outcome of lawsuits against us cannot be predicted with certainty, our management team does not expect these matters to have a material adverse impact on our financial statements.

In May 2008, we received a notice of violation from the Colorado Department of Public Health and Environment, or CDPHE, that alleged that our construction of a pipeline in Garfield County, Colorado was not in compliance with CDHPE's general permit for stormwater discharges associated with construction activities. The notice of violation was based on an inspection of the construction area by CDHPE in May 2007. Although we believe that we corrected any deficiencies promptly after the inspection, CDHPE has proposed a fine of $157,233 for the alleged violations. We are currently engaged in discussions with CDHPE in an effort to resolve this matter.

In February 2009, we received a grand jury subpoena from the U.S. Environmental Protection Agency regarding an alleged unauthorized discharge at a well site near Atoka, Oklahoma in May 2007. Based on information presently available to us, it appears that well fracturing fluids stored by a third party contractor in a tank leaked into a surrounding berm and were later discharged along with rainwater into a nearby waterway. The site was being managed by the contractor at the time of the incident. We have provided the information that was requested by the subpoena. No claim has been made against us with respect to this matter to date, and, based on information presently available to us, we do not believe that our company is a target of the investigation.

Employees

As of December 31, 2009, we had 56 full-time employees, including nine in geology, 12 in production and engineering, 13 in accounting and administration, 17 in land, three in midstream and two senior executives. We also employed a total of 53 contract personnel who assist our full-time employees with respect to specific tasks and 73 outside lease brokers. Our future success will depend partially on our ability to attract, retain and motivate qualified personnel. We are not a party to any collective bargaining agreements and have not experienced any strikes or work stoppages. We consider our relations with our employees to be satisfactory. We utilize the services of independent contractors to perform various field and other services.

MANAGEMENT

Executive Officers and Directors

The following table sets forth names, ages and titles of our executive officers and directors. Each of the individuals listed below holds the position stated below at each of the issuer, Antero and each operating subsidiary.

Name	Age	Title
Peter R. Kagan(1)	42	Director
W. Howard Keenan, Jr.(1)	59	Director
Christopher R. Manning(1)	42	Director
Paul M. Rady	56	Chairman of the Board of Directors and Chief Executive Officer
Glen C. Warren, Jr.	54	Director, President, Chief Financial Officer and Secretary
Kevin J. Kilstrom	55	Vice President—Production
Robert E. Mueller	53	Vice President—Geology
Brian A. Kuhn	51	Vice President—Land
Mark D. Mauz	52	Vice President—Gathering, Marketing and Transportation
Steve M. Woodward	51	Vice President—Business Development
Alvyn A. Schopp	51	Vice President—Accounting & Administration and Treasurer
Kathryn S. Wilson	35	General Counsel and Assistant Secretary

(1) Member of the Audit Committee and the Compensation Committee.

Our directors hold office until the earlier of their death, resignation, removal or disqualification or until their successors have been elected and qualified. Our officers serve at the discretion of the board of directors. There are no family relationships among any of our directors or principal officers.

Peter R. Kagan has served as a director since 2004. Mr. Kagan has been with Warburg Pincus since 1997 and co-leads the firm's investment activities in energy and natural resources. He is also a member of the firm's Executive Management Group. Mr. Kagan received an A.B. degree cum laude from Harvard College and J.D. and M.B.A. degrees with honors from the University of Chicago. Prior to joining Warburg Pincus, he worked in investment banking at Salomon Brothers in both New York and Hong Kong. Mr. Kagan currently also serves on the boards of directors of Broad Oak Energy, Fairfield Energy, Laredo Petroleum, MEG Energy, Resources for the Future, Targa Resources and Targa Resources Partners L.P. In addition, he is a member of the Visiting Committee of the University of Chicago Law School.

W. Howard Keenan, Jr. has served as a director since 2004. Mr. Keenan has over thirty years of experience in the financial and energy businesses. Since 1997, he has been a Member of Yorktown Partners LLC, a private equity investment manager focused on the energy industry. Mr. Keenan currently serves on the Board of Directors of Concho Resources Inc. and GeoMet, Inc. From 1975 to 1997, he was in the Corporate Finance Department of Dillon, Read & Co. Inc. and active in the private equity and energy areas, including the founding of the first Yorktown Partners fund in 1991. He is serving or has served as a director of multiple Yorktown Partners portfolio companies. Mr. Keenan holds an A.B. degree cum laude from Harvard College and an M.B.A. degree from Harvard University.

Christopher R. Manning has served as a director since 2005. Mr. Manning is a Partner of Trilantic Capital Partners, or TCP. Mr. Manning joined TCP in 2009. He was concurrently the Head of Lehman Brothers' Investment Management Division, including both the Asset Management and Private Equity businesses, in Asia-Pacific from 2006 to 2008. He was also a member of the Investment Management Division Global Operating Committee and the Private Equity Division Operating Committee. Lehman Brothers Holdings Inc. filed a voluntary petition for protection under the U.S. bankruptcy code in September 2008. Prior to joining TCP, Mr. Manning was the chief financial officer of The Wing Group, a developer of international power projects. Prior to The Wing Group, he was in the investment banking department of Kidder, Peabody & Co., where he worked on M&A and corporate finance transactions. Mr. Manning also currently serves on the boards of Enduring Resources, The Cross Group and Mediterranean Resources. He holds an M.B.A. from The Wharton School of the University of Pennsylvania and a B.B.A. from the University of Texas at Austin.

Paul M. Rady has served as Chief Executive Officer and Chairman of the Board of Directors since May 2004. Mr. Rady also served as Chief Executive Officer and Chairman of the Board of Directors of our predecessor company, Antero Resources Corporation, from its founding in 2002 to its ultimate sale to XTO Energy, Inc. in April 2005. Prior to Antero Resources Corporation, Mr. Rady served as President, CEO and Chairman of Pennaco Energy from 1998 until its sale to Marathon in early 2001. Prior to Pennaco, Mr. Rady was with Barrett Resources from 1990 until 1998 where he initially was recruited as Chief Geologist in 1990, then served as Exploration Manager, EVP Exploration, President, COO and Director and ultimately CEO. Mr. Rady began his career with Amoco where he served 10 years as a geologist focused on the Rockies and Mid-Continent. Mr. Rady is the managing member of Salisbury Investment Holdings, LLC. Mr. Rady holds a B.A. in Geology from Western State College of Colorado and M.Sc. in Geology from Western Washington University.

Glen C. Warren, Jr. has served as President, Chief Financial Officer and Secretary and as a director since May 2004. Mr. Warren also served as President and Chief Financial Officer and as a director of our predecessor company, Antero Resources Corporation, from its founding in 2002 to its ultimate sale to XTO Energy, Inc. in April 2005. Prior to Antero Resources Corporation, Mr. Warren served as EVP, CFO and Director of Pennaco Energy from 1998 until its sale to Marathon in early 2001. Mr. Warren spent 10 years as a natural resources investment banker focused on equity and debt financing and M&A advisory with Lehman Brothers, Dillon Read and Kidder Peabody. Mr. Warren began his career as a landman in the Gulf Coast region with Amoco, where he spent six years. Mr. Warren is the managing member of Canton Investment Holdings, LLC. Mr. Warren holds a B.A. from the University of Mississippi, a J.D. from the University of Mississippi School of Law and an M.B.A from the Anderson School of Management at U.C.L.A. Mr. Warren has served as a director of Diamond Foods, Inc. since 2005 and served as a director of Venoco Inc. from 2005 to 2008.

Kevin J. Kilstrom has served as Vice President of Production since June 2007. Mr. Kilstrom was a Manager of Petroleum Engineering with AGL Energy of Sydney, Australia from 2006 to 2007. Prior to AGL, Mr. Kilstrom was with Marathon Oil as an Engineering Consultant and Asset Manager from 2003 to 2007 and as a Business Unit Manager for Marathon's Powder River coal bed methane assets from 2001 to 2003. Mr. Kilstrom also served as a member of the board of directors of three Marathon subsidiaries from October 2003 through May 2005. Mr. Kilstrom was an Operations Manager and reserve engineer at Pennaco Energy from 1999 to 2001. Mr. Kilstrom was at Amoco for more than 22 years prior to 1999. Mr. Kilstrom holds a B.S. in Engineering from Iowa State University and an M.B.A. from DePaul University.

Robert E. Mueller has served as Vice President of Geology since April 2005. Mr. Mueller also served as Chief Geologist of our predecessor company, Antero Resources Corporation, from its founding in 2002 to its ultimate sale to XTO Energy, Inc. in April 2005. Prior to Antero Resources Corporation, Mr. Mueller was with Williams as a Director of the Raton Basin asset team in 2001 to 2002. Mr. Mueller was Chief Geologist at Barrett Resources from 1996 to 2001. Mr. Mueller worked as a Senior Geologist for North American Resources from 1993 to 1996 after working the prior 11 years for Amoco Production Company. Mr. Mueller holds a B.S. in Geology from Northern Arizona University and an M.S. in Geology from the University of Wyoming.

Brian A. Kuhn has served as Vice President of Land since April 2005. Mr. Kuhn also served as Vice President of Land of our predecessor company, Antero Resources Corporation, from its founding in 2002 to its ultimate sale to XTO Energy, Inc. in April 2005. From 2001 to 2002, Mr. Kuhn served as Head of Denver Land Department for Marathon Oil. Mr. Kuhn was the Vice President—Land at Pennaco Energy from 1998 to 2001. Mr. Kuhn was a Division Landman with Barrett Resources from

1993 to 1998. Mr. Kuhn was a Landman with Amoco for 13 years prior to 1993. Mr. Kuhn holds a B.B.A. in Petroleum Land Management from the University of Oklahoma.

Mark D. Mauz has served as Vice President of Gathering, Marketing and Transportation since April 2006. From 1993 to 2006, Mr. Mauz was with Duke Energy Field Services, most recently as its Managing Director of the Rockies Region. Mr. Mauz spent from 1990 to 1993 with Amoco in natural gas marketing and 9 years prior to 1990 as a Landman. Mr. Mauz holds a B.S. in Business from the University of Colorado.

Steven M. Woodward has served as Vice President of Business Development since April 2005. Mr. Woodward also served as Vice President of Business Development of our predecessor company, Antero Resources Corporation, from its founding in 2002 to its ultimate sale to XTO Energy, Inc. in April 2005. From 1993 until 2002, Mr. Woodward was in senior business/project development roles with Dynegy. From 1990 to 1992, Mr. Woodward was with Reliance Pipeline Company as a Manager of Business Development. From 1988 to 1990, Mr. Woodward was at Western Gas Resources in a Business Development role. From 1981 to 1988, Mr. Woodward was with ARCO Oil & Gas Company in various engineering roles. Mr. Woodward holds a B.S. in Mechanical Engineering from the University of Colorado.

Alvyn A. Schopp has served as Vice President of Accounting and Administration and Treasurer since January 2005. Mr. Schopp also served as Controller and Treasurer from 2003 to 2005 and as Vice President of Accounting and Administration and Treasurer of our predecessor company, Antero Resources Corporation, from January 2005 until its ultimate sale to XTO Energy, Inc. in April 2005. From 2002 to 2003, Mr. Schopp was an Executive and Financial Consultant with Duke Energy Field Services. From 1993 to 2000, Mr. Schopp was CFO, Director and ultimately CEO of T-Netix. From 1980 to 1993 Mr. Schopp was with KPMG, most recently as a Senior Manager. Mr. Schopp holds a B.B.A. from Drake University.

Kathryn S. Wilson has served as General Counsel and Assistant Secretary since March 2010. From September 2001 to February 2010, Ms. Wilson was an associate with Vinson & Elkins L.L.P. specializing in securities offerings and mergers and acquisitions. Ms. Wilson holds a B.A. from Wesleyan University and a J.D. from the University of Texas School of Law.

Executive Compensation and Other Information

Compensation Discussion and Analysis

Introduction

This Compensation Discussion and Analysis (1) provides an overview of our compensation policies and programs; (2) explains our compensation objectives, policies and practices with respect to our executive officers; and (3) identifies the elements of compensation for each of the individuals identified in the following table, who we refer to in this Compensation Discussion and Analysis as our "Named Executive Officers."

Name	Principal Position
Paul M. Rady	Chairman of the Board of Directors and Chief Executive Officer
Glen C. Warren, Jr.	Director, President, Chief Financial Officer and Secretary
Kevin J. Kilstrom	Vice President—Production
Robert E. Mueller	Vice President—Geology
Alvyn A. Schopp	Vice President—Accounting and Administration

Each of our Named Executive Officers is an employee of Antero Resources Corporation, which is a wholly owned subsidiary of Antero and one of the parent companies of the issuer. Prior to the November 2009 corporate reorganization, the Compensation Committee of the Board of Directors of Antero Resources Corporation approved all compensation decisions for our officers. Since the reorganization, the Compensation Committee of the Board of Directors of Antero, or the Board of Directors of Antero, as appropriate, has approved all compensation decisions for our officers. The Antero Board of Directors and the Antero Resources Corporation Board of Directors are comprised of the same members.

Compensation Philosophy and Objectives of Our Compensation Program

Since our inception in 2002, we have sought to grow our privately held, independent oil and gas company and our compensation philosophy has been primarily focused on recruiting individuals who would be motivated to help us achieve that goal. As a result, from our inception to September 2009, our executive compensation program was primarily designed to attract, retain and motivate our employees by compensating them with significant amounts of equity relative to cash compensation. In particular, we kept our executive officers' total cash compensation at levels that we believed were sufficient to provide them, in the case of salary amounts, with a modest amount of cash that provided them with an adequate means to support their families and, in the case of annual bonus amounts, discretionary amounts that rewarded them for overall individual performance during the year relative to continually evolving company objectives. With respect to non-cash awards, we have historically provided disproportionately greater amounts of equity, which we believed would ultimately compensate our executive officers as they participated in growing our company and maximizing stakeholder value. We also provided additional opportunities for our executive officers to purchase various classes of preferred and common shares in our company on the same basis as our institutional private equity owners for the purpose of aligning the interests of our officers with those of our stakeholders.

Our strategy since September 2009 has been to structure our compensation program so that we may seek out highly qualified and experienced individuals capable of contributing to the continued growth of our development stage company, both in terms of size and enterprise value, and an effective transition into the new obligations we will face as a SEC registrant. Accordingly, over the course of the past several months, we have undertaken various reporting company preparedness initiatives to ensure the competiveness of our executive compensation programs and further align the interests of our executive officers and other employees with the long-term objectives of our company. In particular, we engaged a compensation consultant to benchmark our officers' compensation to ensure that our programs are roughly in the median range of our peer group companies. This engagement is discussed in more detail below under "—Implementing Our Objectives."

Implementing Our Objectives

Role of the Board of Directors, Compensation Committee and our Executive Officers

Executive compensation decisions are typically made on an annual basis by the Compensation Committee with input from Paul M. Rady, our Chief Executive Officer, and Glen C. Warren, Jr., our President and Chief Financial Officer. Specifically, Messrs. Rady and Warren, based on information provided by the compensation consultant and their review of market data, provide recommendations to the Compensation Committee regarding the compensation levels for our existing executive officers (including themselves) and our executive compensation program as a whole. After considering these recommendations, the Compensation Committee typically adjusts base salary levels, determines the amounts of cash bonus awards and determines the amount and vesting of any equity grants for each of our executive officers. In making executive compensation decisions and recommendations, Messrs. Rady and Warren consider the executive officers' performance during the year and the company's performance during the year, but rely primarily on their business judgment and personal experience.

While the Compensation Committee gives considerable weight to Messrs. Rady and Warren's recommendations on compensation matters, the Compensation Committee has the final decision-making authority on all executive compensation matters. No other executive officers have assumed a role in the evaluation, design or administration of our executive officer compensation program.

Role of External Advisors

In September 2009, our management engaged Cogent Compensation Partners, Inc. ("Cogent") to provide periodic executive compensation consulting services. Cogent does not currently provide any other services to our company. Management's objective when hiring Cogent was to assess our level of competitiveness for executive-level talent and receive recommendations for attracting, motivating and retaining key employees in light of our transition into the new obligations we will face as a SEC registrant. As part of its engagement, Cogent:

- Collected and reviewed all relevant company information, including our historical executive compensation data and our organizational structure, and conducted individual interviews with our executive officers and our largest institutional investors to gain insight into the vision, business strategy, culture and effectiveness of our current executive compensation program as well as expectations for the future;

- With the input of management, established a peer group of companies to use for executive compensation comparisons;

- Assessed our compensation program's position relative to the market for our top eight executive officers and our stated compensation philosophy; and

- Prepared a report of its analysis, findings and recommendations for our executive compensation program.

Cogent's report was presented to the Board of Directors as a whole in September 2009. The report was utilized by Messrs. Rady and Warren when making their recommendations to the Board of Directors for the fiscal 2010 compensation decisions.

Competitive Benchmarking

When formulating their compensation recommendations for the Compensation Committee, Messrs. Rady and Warren compare the pay practices for our executive officers against other companies to assist them in the review and comparison of base salary and incentive compensation for our executive officers. This practice recognizes that, while our compensation practices should be competitive in the marketplace, marketplace information is one of the many factors considered in assessing the reasonableness of our executive compensation program.

Prior to September 2009, Messrs. Rady and Warren made informal comparisons of our executive compensation program to the compensation paid to executives of publicly traded and other privately held companies similar in size and location to our company. In December 2008, Messrs. Rady and Warren used a survey from the Mountain States Employers Council as part of their informal competitive market analysis. Messrs. Rady and Warren did not review the data specific to any company participating in this survey and were not familiar with the identities of such companies. Rather, the aggregate data was merely used as a subjective frame of reference for similarly situated officers to help determine a potential range of compensation, which was then balanced against a variety of factors in making a final recommendation of each officer's compensation.

Beginning in September 2009, Messrs. Rady and Warren took a more formal approach and hired Cogent to assess the compensation levels of our top eight executive officers relative to the market. In addition, Messrs. Rady and Warren used statistical information from the 2009 Oil and Gas E&P

Industry Compensation Survey prepared by Effective Compensation, Incorporated ("ECI") to supplement Cogent's peer group data. Messrs. Rady and Warren considered the results of the Cogent and ECI survey data when making their recommendations to the Board of Directors for the fiscal 2010 compensation decisions.

- *Cogent Survey Data.* Cogent used the following parameters when constructing the peer group for its assessment: (1) resource-focused exploration and production companies that are publicly traded (without regard to size), (2) companies with a good performance track record, (3) companies with a strong management team with technical expertise and (4) companies with more than $1.0 billion in enterprise value. Using these parameters and collaborating with Messrs. Rady and Warren, Cogent developed a 19-company industry reference group (the "Cogent Peer Group"). The Cogent Peer Group included the following companies:

  - Berry Petroleum Company
  - Bill Barrett Corporation
  - Cabot Oil & Gas Corporation
  - Carrizo Oil & Gas, Inc.
  - Comstock Resources, Inc.
  - Concho Resources Inc.
  - Continental Resources, Inc.
  - Encore Acquisition Company
  - EXCO Resources, Inc.
  - Newfield Exploration Company
  - Petrohawk Energy Corporation
  - Quicksilver Resources, Inc.
  - Range Resources Corporation
  - Sandridge Energy, Inc.
  - Southwestern Energy Company
  - Ultra Petroleum Corp.

- *ECI Survey Data.* An ECI survey was used because it is specific to the energy industry and derives its data from direct contributions from a large number of participating companies with which we believe we compete for talent. The survey was used to compare our executive compensation program against the following companies, which were selected by Messrs. Rady and Warren, and which have comparable revenues, market capitalization, capital expenditure budgets, business strategies, geographic and geologic focus and number of employees (the "ECI Peer Group"):

  - Berry Petroleum Company
  - Bill Barrett Corporation
  - Cimarex Energy Co.
  - Comstock Resources, Inc.
  - Concho Resources Inc.

- Forest Oil Corporation
- Mariner Energy, Inc.
- Quicksilver Resources Inc.
- St. Mary Land & Exploration Company
- Whiting Petroleum Corporation

Due to the broad responsibilities of our executive officers and our status as a privately held company, comparing survey data to the job descriptions of our executive officers is sometimes difficult. However, as discussed above, our compensation objective is designed to be competitive with the peer companies listed above and, therefore, Messrs. Rady and Warren target compensation levels that are generally in the 50th percentile of the survey information reviewed when formulating their recommendations for the Compensation Committee. We believe that targeting this level of compensation helps us meet our overall total rewards strategy and executive compensation objectives outlined above.

Elements of Compensation

Compensation of our executive officers includes the following key components:

- Base salaries;
- Annual cash incentive payments;
- Transaction bonuses; and
- Long-term equity-based incentive awards.

Base Salaries

Base salaries are designed to provide a minimum, fixed level of cash compensation for services rendered during the year. Base salaries are generally reviewed annually, but are not automatically increased if the Compensation Committee believes that (1) our executives are currently compensated at proper levels in light of either our internal performance or external market factors, or (2) an increase or addition to other elements of compensation would be more appropriate in light of our stated objectives.

In addition to providing a base salary that is competitive with other independent oil and gas exploration and production companies, we also consider internal pay equity factors to appropriately align each of our Named Executive Officer's salary levels relative to the salary levels of our other officers so that it accurately reflects the officer's relative skills, responsibilities, experience and contributions to our company. To that end, annual salary adjustments are based on a subjective analysis of many individual factors, including:

- the responsibilities of the officer;
- the period over which the officer has performed these responsibilities;
- the scope, level of expertise and experience required for the officer's position;
- the strategic impact of the officer's position; and
- the potential future contribution and demonstrated individual performance of the officer.

In addition to individual factors listed above, our overall business performance and implementation of company objectives are taken into consideration. While these metrics generally provide context for making salary decisions, base salary decisions do not depend on attainment of specific goals or performance levels and no specific weighting is given to one factor over another.

Fiscal 2009 Decisions. After reviewing the Mountain States Employers Counsel survey data and considering the individual and business factors described above, Messrs. Rady and Warren recommended, and the Compensation Committee approved, increases in the base salaries of our executive officers in December 2008 as shown in the table below.

Fiscal 2010 Decisions. In October 2009, after comparing base salary levels to the Cogent Peer Group and ECI Peer Group (as described in more detail above under "—Competitive Benchmarking") and considering the individual and business factors described above, Messrs. Rady and Warren recommended, and the Board of Directors approved, increases in the base salaries of our executive officers as shown in the table below. These increases, which were effective as of November 2009, were made as part of the overall shift in our compensation strategy as described in more detail above under "—Compensation Philosophy and Objectives of Our Compensation Program." The adjusted base salary amounts were slightly below or at the median of the Cogent Peer Group and ECI Peer Group.

Executive Officer	Base Salary Prior to December 2008	Base Salary as of December 2008	Percentage Increase	Base Salary as of November 2009	Percentage Increase
	($)	($)	(%)	($)	(%)
Paul M. Rady	235,000	240,000	2	450,000	88
Glen C. Warren, Jr.	218,000	222,500	2	375,000	69
Kevin J. Kilstrom	195,000	200,000	3	280,000	40
Robert E. Mueller	195,000	200,000	3	260,000	30
Alvyn A. Schopp	180,000	185,000	3	275,000	49

Annual Cash Incentive Payments

Annual cash incentive payments, which we also refer to as cash bonuses, are a key part of each Named Executive Officer's annual compensation package. The Compensation Committee believes that discretionary cash bonuses are an appropriate way to further our goals of attracting, retaining, and rewarding highly qualified and experienced officers and avoiding an environment that might cause undue pressure to meet specific financial or individual performance goals. Typically in December of each year, the Compensation Committee determines whether to pay cash bonuses from a bonus pool amount to some or all of our employees, including our executive officers, and, if so, the amount of any such cash bonuses (which may range from 0% to 100% of an executive officer's base salary). The Compensation Committee's decisions are based on recommendations from Messrs. Rady and Warren. The factors considered when determining the amount of discretionary cash bonus awards, if any, are similar to those considered when setting and adjusting base salaries. No particular weight is assigned to any of these factors.

Fiscal 2009 Decisions. A discretionary cash bonus was awarded to each of our Named Executive Officers in November 2009. These awards were based upon the factors noted above. The awards to each Named Executive Officer are reflected below in the "Bonus" column of the Summary Compensation Table.

Transaction Bonuses

Under Antero's limited liability company agreement, a "Transaction Bonus Pool" is created upon a direct or indirect disposition of all or substantially all the assets or equity interests of one of our operating subsidiairies. That Transaction Bonus Pool is an amount equal to three percent (3%) of the profit generated with respect to the disposition of a particular operating subsidiary. Profit is defined pursuant to the terms of Antero's limited liability company agreement. The Transaction Bonus Pool is available to pay bonuses to individuals who are employees of one of our operating subsidiaries as of the date of the disposition (including, potentially, our Named Executive Officers), but the amount of any individual's transaction bonus and whether any particular individual receives a transaction bonus in connection with a disposition will be determined by the Compensation Committee at the time of any disposition of an operating subsidiary. Transaction bonus awards are intended to incentivize our employees to increase the value of our operating subsidiaries for the benefit of our unitholders by allowing them to share in the profits of any disposition of any such operating subsidiary. The amount of any transaction bonus awards made to any employee will be offset against future amounts that such employee would be entitled to receive in connection with future distributions by Antero as a result of the ownership by such employee of certain units in Antero and in Antero Resources Employee Holdings LLC (which are described below under "—Long-Term Equity-Based Incentive Awards").

Long-Term Equity-Based Incentive Awards

Our long-term equity-based incentive program is designed to provide each of our employees with an incentive to focus on the long-term success of our company and to act as a long-term retention tool by aligning the interests of our employees with those of our stakeholders.

Historically, each of the operating subsidiaries sponsored a stock incentive plan from which restricted stock and options were granted to certain employees, including the Named Executive Officers. The Compensation Committee believed that stock options and restricted stock awards incentivized strong performance by our employees, including our executive officers, by providing the opportunity to receive additional compensation as a result of increases in the values of each of the operating subsidiaries. Decisions concerning the granting of stock options and restricted stock awards were made on the same basis, and utilizing the same criteria, as decisions concerning the other compensation elements set forth above. Exercise prices of options granted were pre-determined during the negotiation of our two key equity commitments that were secured in February 2003 and August 2007. This process resulted in the establishment of exercise prices that were sometimes less than the estimated fair market value of the stock underlying the option on the date of grant. Each operating subsidiary's stock options were subject to the following vesting provisions: (1) proportionate vesting to the extent that the officer remained continuously employed on each of the first four anniversaries of a specified vesting commencement date ("time vesting") and (2) proportionate vesting based on the level of preferred equity capital invested in the common stock of the operating subsidiary ("dollar vesting"). Restricted stock awards were also subject to both time vesting and dollar vesting requirements.

The stock incentive plans of each of the operating subsidiaries were terminated immediately prior to the closing of the November 2009 corporate reorganization. In anticipation of the plan terminations and contingent on the closing of the transactions contemplated by our November 2009 corporate reorganization, the boards of directors of each of the operating subsidiaries granted any authorized but unissued in-the-money stock options to certain employees, including certain Named Executive Officers, to ensure that the cash out payments (as described below) would not result in any employee receiving a disproportionately lower level of compensation than the Compensation Committee had anticipated based on the principles and processes outlined above. At the time of the termination of the stock incentive plans, no other equity awards had been granted in 2009. As a result of the stock plan terminations, all of the outstanding options were cancelled through either (1) a mandatory surrender and exercise termination process (as applicable to outstanding options, if any, granted prior to July 13, 2006) ("Non-409A Options") or (2) a discretionary termination and cash out process (as applicable to outstanding options granted on or after July 13, 2006 ("409A Options"), which had been designed to comply with Section 409A ("Section 409A") of the Internal Revenue Code of 1986, as amended (the

"Code"). Specifically, with regard to any Non-409A Options, each executive was provided an opportunity to pay the exercise price under some or all of the agreements relating to such options in exchange for a right to receive the number of our Class A-1 units that the executive would have received in connection with the 2009 corporate reorganization if the executive had been the owner of record of the number of shares of common stock underlying the Non-409A Options. However, none of the executives elected to exercise any of their Non-409A Options and, therefore, these options were cancelled without consideration. In exchange for the cancellation of each executive officer's 409A Options that were (a) vested as a result of both time vesting and dollar vesting (as described above) and (b) considered to be "in-the-money" because the fair market value per share of the shares underlying the option was greater than the exercise price per share of such shares, the executive officer became entitled to receive a cash payment from the applicable operating subsidiary that had granted the officer such option equal to the difference between the fair market value per share and the exercise price per share, less applicable taxes. A portion of the cash out payments necessary to satisfy applicable FICA tax requirements was remitted on behalf of each executive officer in December 2009. However, due to the applicable rules imposed under Section 409A, each operating subsidiary will pay the remaining portion of its respective cash out payment, if any, due to each executive officer in November 2010 without interest. The executive officers will receive the remaining portion of any cash out payments to which they are entitled regardless of whether they remain employed by us. All of the other 409A Options granted to the executive officers that did not constitute vested in-the-money options as of the closing of the November 2009 reorganization were cancelled by the operating subsidiaries effective as of the closing of the November 2009 reorganization without any payment or consideration. Any outstanding restricted stock held by the Named Executive Officers prior to the November 2009 corporate reorganization was either repurchased by the operating subsidiaries at a purchase price equal to the officer's original cost or exchanged for units in Antero in accordance with the Contribution Agreement dated as of November 3, 2009, the stock incentive plans, and the applicable grant agreements. In connection with the termination of the stock incentive plans, each of our employees, including the executive officers, also received a payment equal to $1,000, less applicable taxes, in exchange for signing a release and waiver of all claims and entitlements pursuant to the cancelled options and restricted stock awards granted by the operating subsidiaries.

In connection with the November 2009 corporate reorganization, Antero Resources Employee Holdings LLC ("Holdings") was established to hold a portion of Antero units that were set aside at the time of the reorganization to be used for employee incentive compensation. We grant units in Holdings to our employees, including our Named Executive Officers, as a means of providing them with long-term equity incentive compensation in an affiliated entity that may directly profit from any success we achieve. This structure enables us to identify a fixed number of Antero units on which any distributions will flow through Holdings to our employees. We believe that providing equity compensation from Holdings allows us to retain the ability to incentivize our executives to focus on our long-term success.

In November 2009, we granted certain restricted Class A-2 and Class B-2 unit awards in Holdings to each of our Named Executive Officers. These units are intended to constitute "profits interests" in Holdings that will participate solely in any future profits of Holdings that result from any distributions on our units that are held by Holdings. The allocation of numbers and classes of units in Holdings that were granted to each Named Executive Officer was determined at levels that considered each executives contribution to the growth of the company. The units vest in equal amounts on each of the first four anniversaries of the applicable vesting commencement date set forth in the Named Executive Officer's restricted unit agreement. While the vesting commencement date varies among the awards, the vesting commencement dates applicable to the unit grants were established as of a date that precedes the date on which the units were granted (for example, the Class B-2 units granted to Mr. Rady in November 2009 commenced vesting on August 10, 2007) in order to take into account the Named Executive Officer's prior service to our company. Therefore, as described below under

"—Narrative Disclosure to Summary Compensation Table and Grants of Plan-Based Awards Table," all or a portion of the units granted to each Named Executive Officer were vested on the grant date.

Other Benefits

- *Health and Welfare Benefits.* Our Named Executive Officers are eligible to participate in all of our employee health and welfare benefit plans on the same basis as other employees (subject to applicable law) to meet their health and welfare needs. These plans include medical and dental insurance, as well as medical and dependent care flexible spending accounts. These benefits are provided in order to ensure that we are able to competitively attract and retain officers and other employees. This is a fixed component of compensation, and these benefits are provided on a non-discriminatory basis to all employees.

- *Retirement Benefits.* We maintain an employee retirement savings plan whereby employees may save for retirement or future events on a tax-advantaged basis. We have made only one employer discretionary contribution, in 2004, to the 401(k) plan on behalf of our participating employees. Participation in the 401(k) plan is at the discretion of each individual employee, and our Named Executive Officers participate in the plan on the same basis as all other employees.

- *Perquisites and Other Personal Benefits.* We believe that the total mix of compensation and benefits provided to our executive officers is currently competitive and, therefore, perquisites should not play a significant role in our executive officers' total compensation.

Employment, Severance or Change in Control Agreements

We do not currently maintain any employment, severance or change in control agreements with any of our Named Executive Officers.

As discussed below under "—Potential Payments Upon a Termination or a Change in Control," the Named Executive Officers could be entitled to receive certain payments or accelerated vesting of any of their unit awards that remain unvested upon their termination of employment with us under certain circumstances or the occurrence of certain corporate events.

Other Matters

Equity Ownership Guidelines and Hedging Prohibition

We do not currently have ownership requirements or an equity retention policy for our Named Executive Officers. We do not have a policy that restricts our executive officers from limiting their economic exposure to our equity. We will continue to periodically review best practices and reevaluate our position with respect to equity ownership guidelines and hedging prohibitions.

Tax and Accounting Treatment of Executive Compensation Decisions

The Board of Directors has not yet adopted a policy with respect to the limitation under Section 162(m) of the Code, which generally limits our ability to deduct compensation in excess of $1,000,000 to a particular executive officer in any year.

Summary Compensation

The following table summarizes, with respect to our Named Executive Officers, information relating to the compensation earned for services rendered in all capacities during the fiscal year ended December 31, 2009.

Summary Compensation Table for the Year Ended December 31, 2009

Name and Principal Position	Year	Salary ($)	Bonus ($)	Option Awards(1) ($)	All Other Compensation (2) ($)	Total ($)
Paul M. Rady *(Chairman of the Board of Directors and Chief Executive Officer)*	2009	$ 275,000	$ 225,000	$ 168,013	$ 293,467	$ 961,480
Glen C. Warren, Jr. *(Director, President and Chief Financial Officer and Secretary)*	2009	$ 247,917	$ 175,000	$ 111,120	$ 195,967	$ 730,004
Kevin J. Kilstrom *(Vice President—Production)*	2009	$ 213,333	$ 140,000	$ —	$ 348,973	$ 702,306
Robert E. Mueller *(Vice President—Geology)*	2009	$ 210,000	$ 110,000	$ 78,006	$ 229,406	$ 627,412
Alvyn A. Schopp *(Vice President—Accounting & Administration and Treasurer)*	2009	$ 200,000	$ 140,000	$ 150,007	$ 96,700	$ 586,707

(1) Represents the aggregate grant date fair value of the options granted in fiscal 2009, calculated in accordance with FASB ASC Topic 718. The valuation assumptions used in determining these amounts are described in Note 10 to the financial statements included elsewhere in this prospectus.

(2) Represents the total amounts due to each executive officer as a result of the termination of the stock incentive plans of the operating subsidiaries. The amounts consist of (a) a waiver payment paid to each officer in exchange for signing a release and waiver of all claims and entitlements pursuant to the cancelled options and restricted stock awards and (b) the amount of cash out payments due with respect to certain vested in-the-money options that were cancelled in 2009. The following table sets forth the amounts in the "All Other Compensation" column with respect to each of the items described in (a) and (b) above.

Name	Waiver Payments	Cash Out Payments for Cancelled Options Granted Prior to 2009(a)	Total
Paul M. Rady	$ 1,000	$ 292,467	$ 293,467
Glen C. Warren, Jr.	$ 1,000	$ 194,967	$ 195,967
Kevin J. Kilstrom	$ 1,000	$ 347,973	$ 348,973
Robert E. Mueller	$ 1,000	$ 228,406	$ 229,406
Alvyn A. Schopp	$ 1,000	$ 95,700	$ 96,700

(a) Represents the cash out payments due with respect to vested in-the-money options accrued in 2009. Our executive officers are not required to perform any additional services in order to receive such payments. However, in accordance with the applicable

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rules under Section 409A, such payments will be paid by the applicable subsidiary during November 2010 without interest.

Grants of Plan-Based Awards for Fiscal Year 2009

The following table provides information concerning each award granted to our Named Executive Officers under any plan, including awards, if any, that have been transferred during the fiscal year ended December 31, 2009.

Grants of Plan-Based Awards for the Year Ended December 31, 2009

Name	Grant Date	All Other Stock Awards: Number of Shares of Stock or Units(1) (#)	All Other Option Awards: Number of Securities Underlying Options (#)	Exercise or Base Price of Option Awards(7) ($/Sh)	Grant Date Fair Value of Stock and Option Awards(8)(9) ($)
Paul M. Rady	10/28/2009	—	12,096(2)	$ 3.75	$ 168,013
	11/03/2009	113,670(5)	—	$ —	$ —
	11/03/2009	500,000(6)	—	$ —	$ —
Glen C. Warren, Jr.	10/28/2009	—	8,000(2)	$ 3.75	$ 111,120
	11/03/2009	75,780(5)	—	$ —	$ —
	11/03/2009	333,333(6)	—	$ —	$ —
Kevin J. Kilstrom	11/20/2009	200,000(5)	—	$ —	$ —
	11/20/2009	400,000(6)	—	$ —	$ —
Robert E. Mueller	10/28/2009	—	5,616(2)	$ 3.75	$ 78,006
	11/20/2009	80,600(5)	—	$ —	$ —
	11/20/2009	5,000(5)	—	$ —	$ —
	11/20/2009	400,000(6)	—	$ —	$ —
Alvyn A. Schopp	10/28/2009	—	5,509(3)	$ 2.50	$ 88,199
	10/28/2009	—	640(4)	$ 2.50	$ 21,773
	10/28/2009	—	1,396(4)	$ 20.00	$ 23,062
	10/28/2009	—	1,222(2)	$ 3.75	$ 16,974
	11/20/2009	45,000(5)	—	$ —	$ —
	11/20/2009	5,000(5)	—	$ —	$ —
	11/20/2009	125,000(6)	—	$ —	$ —

(1) Represents the number of restricted Class A-2 and/or Class B-2 units in Holdings granted pursuant to the Limited Liability Company Agreement of Holdings ("Holdings LLC Agreement"). For more information concerning these awards, see the discussion above under "—Compensation Discussion and Analysis—Elements of Compensation—Long-Term Equity-Based Incentive Awards." As described below under "—Payments Upon Termination or Change in Control," the awards may terminate or be subject to accelerated vesting upon the officer's termination of employment or the occurrence of certain corporate events.

(2) Represents options to purchase shares of the Class C common stock of Antero Resources Midstream Corporation ("Midstream") that were granted pursuant to the Midstream Amended and Restated 2006 Stock Incentive Plan (the "Midstream Plan"). These options were immediately vested and cancelled in connection with the termination of the Midstream Plan. The cash out payment, if any, due with respect to the cancellation of such options will be paid by Midstream in November 2010.

(3) Represents options to purchase the Class A common stock of Midstream that were granted pursuant to the Midstream Plan. These options were immediately vested and cancelled in connection with the termination of the Midstream Plan. The cash out payment, if any, due with respect to the cancellation of such options will be paid by Midstream in November 2010.

(4) Represents options to purchase the Class A common stock of Antero Resources Pipeline Corporation ("Pipeline") that were granted pursuant to the Pipeline Amended and Restated 2006 Stock Incentive Plan (the "Pipeline Plan"). These options were immediately vested and cancelled in connection with the termination of the Pipeline Plan. The cash out payment, if any, due with respect to the cancellation of such options will be paid by Pipeline in November 2010.

(5) Represents awards of restricted Class A-2 units in Holdings.

(6) Represents awards of restricted Class B-2 units in Holdings.

(7) There is no exercise or base price for the restricted Class A-2 and Class B-2 unit awards that are reflected in the "All Other Stock Awards: Number of Shares of Stock or Units" column.

(8) The fair market values of the options to purchase shares of common stock of the operating subsidiaries were determined as follows: (a) our Board of Directors received and studied the gross asset values of each of the operating subsidiaries determined through an independent appraisal (the "Appraisal") conducted by the valuation division of an investment banking firm of recognized national standing with valuation expertise in the oil and gas exploration and production sector that received a fixed fee for its work in performing the Appraisal, which fee was not dependent in any manner on the outcome of the Appraisal; and (b) the Board of Directors applied a valuation methodology to such gross asset values that took into account the following factors, as applicable: (i) recent arms' length transactions involving the sale or transfer of each subsidiary's common stock, (ii) discounts for the lack of marketability of such stock, (iii) whether the valuation method was used for other material purposes of the operating subsidiary, its stockholders or creditors, and (iv) other relevant factors, including, without limitation, the capital structure of each operating subsidiary.

(9) The fair market value of each class of units in Holdings was determined based on the aggregate gross asset values of the operating subsidiaries determined through the Appraisal and adjusted to reflect the distribution rights of Holdings with respect to our units pursuant to the Holdings LLC Agreement.

Narrative Disclosure to Summary Compensation Table and Grants of Plan-Based Awards Table

The following is a discussion of material factors necessary to an understanding of the information disclosed in the Summary Compensation Table and the Grants of Plan-Based Awards Table set forth above.

Stock Awards

The stock awards reflected above in the "Grants of Plan-Based Awards for Year Ended December 31, 2009" table consist of restricted Class A-2 and Class B-2 units in Holdings. Although these awards were granted in November 2009, the vesting commencement dates applicable to the units granted to each of the Named Executive Officers were set as of a date that precedes the date on which the units were granted in order to take into account service to the company prior to the November 2009 reorganization. Therefore, because all or a portion of the units granted to each Named Executive Officer were vested upon the date of grant, portions of the units granted in 2009 are not reflected below in the "Outstanding Equity Awards Value at 2009 Fiscal Year-End" table.

The Vesting Commencement Dates applicable to the Class A-2 units in Holdings are as follows: Messrs. Rady and Warren—June 20, 2002; Mr. Mueller—August 2, 2002 for 80,600 units and December 10, 2003 for 5,000 units; Mr. Kilstrom—June 4, 2007; Mr. Schopp—May 1, 2003 for 45,000 units and December 10, 2003 for 5,000 units. The Vesting Commencement Date applicable to all Class B-2 units in Holdings granted to each of the Named Executive Officers is August 10, 2007. Absent a termination of employment prior to full vesting of the awards (as described further below in the "—Potential Payments Upon Termination or Change of Control"), full vesting will occur on the fourth year anniversary of the applicable Vesting Commencement Date.

Options Awards

As reflected above in the "Grants of Plan-Based Awards for Year Ended December 31, 2009" table, each of the options granted to the Named Executive Officers were fully vested upon the date of grant. Prior to the November 2009 corporate reorganization, the boards of directors of the operating subsidiaries determined that certain Named Executive Officers would not receive the amount of compensation that the Compensation Committee had originally intended for such officers to receive pursuant to the settlement of previously granted equity-based compensation awards, particularly with respect to certain outstanding option awards. Therefore, to the extent that the applicable stock incentive plan had outstanding shares remaining available for issuance, certain Named Executive Officers were granted "in-the-money" options as an assurance that the officer would indeed receive the level of compensation that the Compensation Committee had originally intended. Immediately prior to the corporate reorganization and in connection with the termination of the stock incentive plans pursuant to which such options were granted, the options described in the table above were cancelled. As a result of the cancellation, each Named Executive Officer became entitled to receive a cash payment during fiscal 2010 from the applicable operating subsidiary that granted the officer that option equal to the difference between the fair market value per share of each such option and the exercise price per share, less applicable taxes.

Salary and Cash Incentive Awards in Proportion to Total Compensation

The following table sets forth the approximate percentage of each Named Executive Officer's total compensation that we paid in the form of base salary and annual cash incentive awards during fiscal 2009.

Name	Percentage of Total Compensation
Paul M. Rady	52%
Glen C. Warren, Jr.	58%
Kevin J. Kilstrom	50%
Robert E. Mueller	51%
Alvyn A. Schopp	58%

Outstanding Equity Awards Value at 2009 Fiscal Year-End

The following table provides information concerning stock that has not vested for our Named Executive Officers as of December 31, 2009. No stock options remained unvested as of December 31, 2009.

Outstanding Equity Awards as of December 31, 2009

	Stock Awards			
Name	Number of Shares of Units of Stock That Have Not Vested	Market Value of Shares or Units of Stock That Have Not Vested(7)	Equity Incentive Plan Awards: Number of Unearned Shares, Units or Other Rights That Have Not Vested	Equity Incentive Plan Awards: Market or Payout Value of Unearned Shares, Units or Other Rights That Have Not Vested(8)
	(#)	($)	(#)	($)
Paul M. Rady				
Restricted Award Units(1)	—	$ —	250,000(4)	$ —
Glen C. Warren, Jr.				
Restricted Award Units(1)	—	$ —	166,667(4)	$ —
Kevin J. Kilstrom				
Restricted Award Units(1)	—	$ —	100,000(6)	$ —
Restricted Award Units(1)	—	$ —	200,000(5)	$ —
Class I-3 Units(2)	8,000(3)	$ —	—	$ —
Class B-1 Units(2)	100,000(3)	$ —	—	$ —
Class B-3 Units(2)	63,492(3)	$ —	—	$ —
Class B-5 Units(2)	30,769(3)	$ —	—	$ —
Robert E. Mueller				
Restricted Award Units(1)	—	$ —	200,000(5)	$ —
Alvyn A. Schopp				
Restricted Award Units(1)	—	$ —	62,500(5)	$ —

(1) Represents the number of restricted Class A-2 and/or Class B-2 units in Holdings granted pursuant to the Holdings LLC Agreement. For more information concerning these awards, see the discussion above under "—Compensation Discussion and Analysis—Elements of Compensation—Long-Term Equity-Based Incentive Awards." As described below under "—Payments Upon Termination or Change in Control," the restricted unit awards may terminate or be subject to accelerated vesting upon the officer's termination of employment or the occurrence of certain corporate events. Please see footnotes 4, 5 and 6 below for a description of the vesting schedule for the awards that remained outstanding as of December 31, 2009.

(2) Reflects awards that were originally issued by certain of the operating subsidiaries as restricted stock awards with respect to the subsidiary's Series C preferred stock and Series D, E, and F common stock. In connection with the November 2009 corporate reorganization, all awards were exchanged for Class I-3, B-1, B-3 and B-5 units in Antero. The vesting conditions associated with the original restricted stock awards were kept in place upon exchange. Please see footnote 3 below for a description of the awards that remained outstanding as of December 31, 2009.

(3) Represents awards that were granted on August 10, 2007 with a vesting commencement date of August 10, 2007. The awards vested 20% upon issuance and the remaining portion will vest 20% on each of the first four anniversaries of the vesting commencement date.

(4) Represents non-vested restricted unit awards that were granted on November 3, 2009 with a vesting commencement date of August 10, 2007. The awards vest 25% per year beginning on the first anniversary of the vesting commencement date.

(5) Represents non-vested restricted unit awards that were granted on November 20, 2009 with a vesting commencement date of August 10, 2007. The awards vest 25% per year beginning on the first anniversary of the vesting commencement date.

(6) Represents non-vested restricted unit awards that were granted on November 20, 2009 with a vesting commencement date of June 4, 2007. The awards vest 25% per year beginning on the first anniversary of the vesting commencement date.

(7) The fair market value of each class of units in Antero was determined based on the aggregate gross asset values of the operating subsidiaries determined through the Appraisal and adjusted to reflect the distribution rights of Antero with respect to our units pursuant to Antero's LLC Agreement.

(8) The fair market value per unit of each class of units in Holdings subject to the restricted unit awards was $0.00 at the time of issuance of the awards. Therefore, there is no market value associated with the unvested portion of the awards.

Option Exercises and Stock Vested in Fiscal Year 2009

The following table provides information concerning each vesting of stock, including restricted stock, restricted stock units and similar instruments, during fiscal 2009 on an aggregated basis with respect to each of our Named Executive Officers. No options were exercised during fiscal 2009 because all options were terminated.

Option Exercises and Stock Vested for the Year Ended December 31, 2009

Name	Stock Awards Number of Shares Acquired on Vesting(1) (#)	Value Realized Upon Vesting(2) ($)
Paul M. Rady	—	$ —
Glen C. Warren, Jr.	—	$ —
Kevin J. Kilstrom		
Class I-3 Units(3)	4,000	$ —
Class B-1 Units(3)	50,000	$ —
Class B-3 Units(3)	31,746	$ —
Class B-5 Units(3)	15,385	$ —
Robert E. Mueller	—	$ —
Alvyn A. Schopp		
Class I-3 Units(3)	6,000	$ —
Class B-1 Units(3)	75,000	$ —
Class B-3 Units(3)	21,429	$ —
Class B-5 Units(3)	23,077	$ —

(1) The number of shares acquired on vesting represents the gross number of units vested. There were no payroll taxes withheld from these awards.

(2) The value realized upon vesting was the gross number of units vested multiplied by the fair market value of the units. Because our units do not have a public market value and we do not measure the awards on a regular basis, the value realized upon vesting is the value at the point of the last measurement of our units, which was November 3, 2009, the date of the corporate reorganization. The fair market value per unit of each class of our units on that date was $0.00.

(3) Reflects awards that were originally issued by certain of the operating subsidiaries as restricted stock awards with respect to the subsidiary's Series C preferred stock and Series D, E, and F common stock. In connection with the November 2009 corporate reorganization, any vested awards were exchanged for Class I-3, B-1, B-3 and B-5 units in Antero. The vesting conditions associated with the original restricted stock awards were kept in place upon exchange.

Payments Upon Termination or Change in Control

Holdings Units. As described above, we do not maintain individual employment agreements, severance agreements or change in control agreements with the Named Executive Officers; however, each of the Named Executive Officers have been awarded certain units in Holdings that may be affected by the officer's termination of employment or the occurrence of certain corporate events. The impact of such a termination or corporate event upon the units is governed by the terms of both the individual award agreements issued to the officers in connection with the grant of the unit awards, as well as the Holdings LLC Agreement.

The Holdings LLC Agreement provides that upon the termination of a Named Executive Officer's employment with us by reason of death or "disability" (as defined below) or the occurrence of an "exit event" (as defined below) while the Named Executive Officer is employed by us, any unvested portion of the Holdings units granted to the Named Executive Officer will become vested; our termination of the Named Executive Officer's employment with or without "cause," as well as the officer's voluntary termination of employment, generally results in the forfeiture of all unvested Holdings units. In addition, a termination for "cause" results in a forfeiture of all vested units. Any unvested portion of the Holdings units granted to a Named Executive Officer may also become vested upon a "qualified IPO" (as defined below) or under such other circumstances and at such times as the Board of Directors of Holdings determines to be appropriate in its discretion.

The Holdings LLC Agreement also provides that upon the voluntary resignation of a Named Executive Officer or the occurrence of an exit event, any portion of the Holdings units granted to the officer that have vested as of the time of the applicable event are subject to repurchase at Holdings' option at a purchase price equal to the "fair market value" of such units, as determined by the unanimous resolution of the Board of Directors. Such amount may be paid by Holdings in cash or by promissory note. In addition to the acceleration of vesting described above, in the event of a qualified IPO, the Board of Directors of Holdings may, but is not required to, affect one of the following actions in its discretion: (1) require some or all of the Named Executive Officers to surrender some or all of their vested units in Holdings in exchange for an amount of cash or stock per unit equal to the fair market value of such units; (2) make appropriate adjustments to such units; or (3) require the forfeiture of any unvested Holdings units.

At the time of the repurchase of any unit awards in Holdings which occurs at the termination of the employee's employment relationship with us or any of our subsidiaries, any amounts received as a transaction bonus award that have not already been offset against previous unit distributions will be offset against the purchase price to be paid by Holdings for the repurchase of such units.

Under the Holdings LLC Agreement, a Named Executive Officer will be considered to have incurred a "disability" if the officer becomes incapacitated by accident, sickness or other circumstance that renders the officer mentally or physically incapable of performing the officer's duties with us on a full-time basis for a period of at least 120 days during any 12-month period. A termination for "cause" will occur following an employee's (1) gross negligence or willful misconduct, (2) conviction of a felony or a crime involving theft, fraud or moral turpitude, (3) refusal to perform material duties or responsibilities, (4) willful and material breach of a corporate policy or code of conduct or (5) willfully engagement in conduct that damages the integrity, reputation or financial success of Antero or any of its affiliates. Further, an "exit event" generally includes the sale of our company, in one transaction or a series of related transactions, whether structured (1) as a sale or other transfer of all or substantially all of our units (including by way of merger, consolidation, share exchange, or similar transaction); or (2) the sale or other transfer of all or substantially all of our assets promptly followed by a dissolution and liquidation of our company; or (3) a combination of both. A "qualified IPO" means the offering and sale of equity interests or securities in Antero or one of its subsidiaries in a firm commitment underwritten public offering registered under the Securities Act of 1933, as amended, that results in (1) aggregate cash proceeds of not less than $50,000,000 (without deducting underwriting discounts, expenses, and commissions) and (2) the listing of such interests or securities on the New York Stock Exchange, the NYSE Euronext or the Nasdaq Stock Market.

Antero Units. At the time of the 2009 reorganization, Mr. Kilstrom was the only Named Executive Officer that held outstanding unvested restricted stock awards with respect to the operating subsidiaries' Series C preferred stock and Series D, E, and F common stock. Pursuant to the Contribution Agreement entered into as of November 3, 2009 among Antero, each of the operating subsidiaries, certain institutional investors of the operating subsidiaries and members of our management team, these awards were exchanged for Class I-3, B-1, B-3 and B-5 units in Antero and the units retained the same vesting schedules as the original awards. Thus, half of Mr. Kilstrom's Class I-3, B-1, B-3 and B-5 units that remain outstanding will vest on August 10, 2010, and the remaining half will vest on August 10, 2011, subject to certain forfeiture restrictions described below.

The Antero units Mr. Kilstrom received in connection with such exchange will also vest in accordance with the terms and conditions contained within the Antero limited liability company agreement. Upon Mr. Kilstrom's death or "disability," any unvested units will immediately vest. In the event Mr. Kilstrom is terminated without "cause," or he voluntarily resigns, his unvested Antero units will become subject to repurchase at his original cost for such units, if any. Mr. Kilstrom's termination for "cause" will subject his units to repurchase at their original cost. Any vested units in Antero that Mr. Kilstrom holds upon his voluntary resignation will also be subject to repurchase, although such a repurchase would occur at the fair market value of the units at the time of repurchase rather than his original cost for the units. The terms "disability" and "cause" are defined in the Antero limited liability company agreement based on the meanings ascribed to such terms in the Holdings LLC Agreement described above.

All time-based vesting restrictions will also lapse with respect to Mr. Kilstrom's Antero units upon the occurrence of a change of control. The Antero limited liability company agreement generally defines a "change of control" as (1) the disposition of Antero's membership interests, a merger or similar transaction that results in Antero's members immediately prior to the transaction no longer representing a majority of Antero's membership immediately following such transaction, (2) the sale of all or substantially all of Antero's assets, or (3) the consolidation or other form of reorganization that results in Antero's membership interests being exchanged for (or converted into) cash, securities or other property of an entity in which the Antero members do not also own a majority of the voting power. However, in the event Antero conducts a public offering of its interests, certain members of Antero may, in accordance with the terms of the Antero limited liability company agreement, determine that such a transaction does not constitute a change of control.

Potential Payments Upon Termination or Change in Control Table for Fiscal 2009

The information set forth in the table below is based on the assumption that the applicable triggering event occurred on December 31, 2009, the last business day of fiscal 2009. Accordingly, the information reported in the table is our best estimation of our obligations to each Named Executive Officer and will only be determinable with any certainty upon the occurrence of the applicable event. In order to provide the most accurate information possible, neither the acceleration of vesting nor any repurchase rights that are subject to the absolute discretion of either Holdings' or Antero's Board of Directors have been taken into account for purposes of calculating the values set forth in the table below. Note, however, that because the fair market value per unit of each applicable unit in Holdings and Antero was $0.00 on December 31, 2009, we would not have had any financial obligation to provide benefits to any of the Named Executive Officers upon a termination of employment by reason of death or disability nor upon the occurrence of an exit event as of December 31, 2009.

Name	Termination of Employment by Reason of Death or Disability	Occurrence of an Exit Event or a Change of Control
Paul M. Rady		
Class B-2 Units(1)	$ —	$ —
Glen C. Warren, Jr.		
Class B-2 Units(1)	$ —	$ —
Kevin J. Kilstrom		
Class A-2 Units(2)	$ —	$ —
Class B-2 Units(1)	$ —	$ —
Class I-3 Units(3)	$ —	$ —
Class B-1 Units(3)	$ —	$ —
Class B-3 Units(3)	$ —	$ —
Class B-5 Units(3)	$ —	$ —
Robert E. Mueller		
Class B-2 Units(1)	$ —	$ —
Alvyn A. Schopp		
Class B-2 Units(1)	$ —	$ —

(1) The numbers of unvested Holdings Class B-2 units that would have been subject to accelerated vesting as of December 31, 2009 for each of the officers above are as follows: Mr. Rady—250,000; Mr. Warren—166,667; Mr. Mueller—200,000; Mr. Kilstrom—100,000; and Mr. Schopp—62,500.

(2) The number of unvested Holdings Class A-2 units that would have been subject to accelerated vesting as of December 31, 2009 for Mr. Kilstrom was 200,000.

(3) Mr. Kilstrom held 8,000 Class I-3 units, 100,000 Class B-1 units, 63,492 Class B-3 units, and 30,769 Class B-5 units in Antero that could have potentially been subject to accelerated vesting as of December 31, 2009

Compensation of Directors

The employee and non-employee members of the Board of Directors do not receive compensation for their services as directors. However, our directors may be reimbursed for their expenses in attending board meetings.

Corporate Governance Matters

Our board of directors has appointed an audit committee and a compensation committee. Messrs. Kagan, Keenan and Manning serve as the members of those committees. Because the registration statement of which this prospectus forms a part registers only debt securities and because we do not have and are not seeking to list any securities on a national securities exchange or on an inter-dealer quotation system, we are not subject to a number of the corporate governance requirements of the SEC or of any national securities exchange or inter-dealer quotation system. For example, we are not required to have a board of directors comprised of a majority of independent directors or to have an audit committee comprised of independent directors. Accordingly, our board of directors has not made any determination as to whether any of the members of our board of directors or committees thereof would qualify as independent under the listing standards of any national securities exchange or any inter-dealer quotation system or under any other independence definition.

Compensation Committee Interlocks and Insider Participation

None of our executive officers has served as a director or member of the compensation committee of any other entity whose executive officers served as a director or member of our compensation committee.

Certain Relationships and Related Party Transactions

To date, our equity investors, including our Chief Executive Officer and our President, Chief Financial Officer and Secretary, have invested approximately $1.4 billion in us. For a description of our ownership structure and the ownership of the equity interests in Antero by its principal equity holders and by our directors and executive officers, see "Business—Corporate Sponsorship and Structure" and "Our Principal Owners." We do not currently have any formal policy with respect to the review and approval of related party transactions.

Antero Limited Liability Company Agreement

Antero was formed in connection with our November 2009 corporate reorganization. The limited liability company agreement of Antero provides for a number of different classes of units, which are owned by Antero's equity investors and employees. Under Antero's limited liability company agreement, if Antero proposes to issue certain additional equity securities prior to any initial public offering of its equity securities, certain of the existing holders of Antero's units who are "accredited investors' under the Securities Act will have the right to purchase a pro rata amount of such securities. Certain of the units are subject to rights of first refusal held by Antero and the other members. In addition, if, after complying with the applicable rights of first refusal, any member seeks to sell any units, the terms of such sale must include, from the third party buyer, an offer to purchase, on the same terms, a proportional number of units of the same class of units to be sold by such selling member from each member that holds units of the class that the selling member is proposing to sell. Furthermore, if holders of at least 69% of certain classes of units and the director designated by Warburg Pincus approve a sale of Antero, then all members will be required both to approve the sale and to agree to sell all of their units on the terms and conditions of such approved sale.

None of Antero's outstanding units are entitled to current cash distributions or are convertible into indebtedness, and Antero has no obligation to repurchase these units at the election of the unitholders. Although Antero is required to make quarterly distributions to cover any income taxes allocated to each unitholder, the unitholders have no other rights to cash distributions (except in the case of certain liquidation events). We do not anticipate making any such tax distributions in the foreseeable future. Pursuant to the terms of Antero's limited liability company agreement, upon certain liquidation events, units held by our private equity sponsors and institutional investors are entitled to receive, prior to any amounts received by other unitholders, an amount equal to the initial purchase price of such units plus a special distribution with respect to such units and will continue to participate on a pro rata basis with other unitholders in any excess funds available in liquidation.

The board of directors of Antero currently consists of five members who have been designated in accordance with Antero's limited liability company agreement. Each of Warburg Pincus, Yorktown Energy Partners and Trilantic Capital Partners currently has the right to designate one director to the board of directors of Antero. The remaining two members of Antero's board of directors are our Chief Executive Officer and our Chief Financial Officer. Warburg Pincus currently has the right to designate one additional member of Antero's board of directors after consultation with the management directors and the other investors in Antero.

Antero Resources Employee Trust

Concurrent with the closing of the November 2009 corporate reorganization, Antero issued profits interests to Antero Resources Employee Trust, LLC, a newly formed Delaware limited liability company, owned solely by certain of our officers and employees. These profits interests only participate in distributions upon liquidation events meeting certain requisite financial return thresholds. In turn, Antero Resources Employee Trust issued similar profits interests to certain of our officers and employees.

Registration Rights Agreement

In connection with the November 2009 restructuring, Antero entered into a registration rights agreement with its members pursuant to which Antero granted certain demand and "piggyback" registration rights to such members.

Under the registration rights agreement, a requisite number of members of Antero may at any time prior to the earlier to occur of an initial public offering by Antero of its equity securities or August 10, 2010, require Antero to file a registration statement for the public sale of their equity securities in Antero. In addition, if, any time after an initial public offering of its equity securities, Antero proposes to file a registration statement with respect to an offering of its equity securities, each of the members will have the right to include his or its equity securities in that offering. The underwriters of any underwritten offering will have the right to limit the number of equity securities of the members to be included in such underwritten offering.

We will pay all expenses relating to any demand or piggyback registration, except for underwriters' or brokers' commission or discounts. The securities covered by the registration rights agreement will no longer be registrable under the registration rights agreement if they have been sold to the public either pursuant to a registration statement or under Rule 144 promulgated under the Securities Act or are otherwise eligible for resale pursuant to Rule 144(b) under the Securities Act.

OUR PRINCIPAL OWNERS

The five operating subsidiaries together own all of the outstanding shares of common stock of the issuer. Antero owns all of the outstanding shares of common stock of each of the five operating subsidiaries.

The following table sets forth the number of voting units in Antero beneficially owned by (1) all persons who, to the knowledge of our management team, beneficially own more than 5% of the outstanding voting units of Antero, (2) each current director of Antero, (3) Antero's named executive officers and (4) all current directors and executive officers of Antero as a group. This information reflects our November 2009 corporate restructuring and equity placements. See "Business—Corporate Sponsorship and Structure."

Name	Total Number of Voting Units	Percent of Total Units Outstanding
Warburg Pincus(1)	56,557,133	40.8%
Yorktown Energy Partners(2)	15,942,448	11.5%
Trilantic Capital Partners(3)	12,471,533	9.0%
Peter R. Kagan(4)	—	—
W. Howard Keenan, Jr.(5)	—	—
Christopher R. Manning(6)	—	—
Paul M. Rady(7)	21,125,461	15.2%
Glen C. Warren, Jr.(8)	14,083,641	10.2%
Robert E. Mueller	827,302	0.6%
Alvyn A. Schopp	855,574	0.6%
Kevin J. Kilstrom	530,653	0.4%
Directors and executive officers as a group (12 persons)	39,515,015	28.5%

(1) The holdings of Warburg Pincus are held by WP Antero LLC. WP Antero LLC is a subsidiary of Warburg Pincus Private Equity X, L.P., Warburg Pincus Private Equity VIII, L.P. and certain of their affiliated funds, which we collectively refer to as the Warburg Pincus Funds, all of which are managed by Warburg Pincus LLC. Warburg Pincus & Co. is the indirect general partner of Warburg Pincus Funds.

(2) The holdings of Yorktown Energy Partners are collectively held by Yorktown Energy Partners V, L.P., Yorktown Energy Partners, VI, L.P., Yorktown Energy Partners VII, L.P. and Yorktown Energy Partners VIII, L.P.

(3) The holdings of Trilantic Capital Partners are collectively held by investment vehicles and individuals affiliated with Trilantic Capital Partners III L.P. and Trilantic Capital Partners IV L.P.

(4) Peter R. Kagan, one of our directors, is a general partner of Warburg Pincus & Co., a managing director and member of Warburg Pincus LLC and a limited partner of certain Warburg Pincus Funds. Mr. Kagan was elected to our board of directors as a Warburg Pincus designee. Mr. Kagan disclaims beneficial ownership of all units owned by the Warburg Pincus entities.

(5) W. Howard Keenan, Jr., one of our directors, is a member and a manager of the general partner of and a limited partner of each of Yorktown Energy Partners V, L.P., Yorktown Energy Partners VI, L.P., Yorktown Energy Partners VII, L.P. and Yorktown Energy Partners VIII, L.P. and holds all securities received as director compensation for the benefit of those entities. Mr. Keenan disclaims beneficial ownership of all such securities

as well as those held by Yorktown Energy Partners V, L.P., Yorktown Energy Partners VI, L.P., Yorktown Energy Partners VII, L.P. and Yorktown Energy Partners VIII, L.P. except to the extent of his pecuniary interest therein. Mr. Keenan was elected to our board of directors as a Yorktown Energy Partners designee.

(6) Christopher R. Manning, one of our directors, is partner of Trilantic Capital Partners. Mr. Manning was elected to our board of directors as a Trilantic Capital Partners designee. Mr. Manning disclaims beneficial ownership of all units owned by the Trilantic Capital Partners entities.

(7) Mr. Rady, our Chief Executive Officer and Chairman of the Board and one of our directors, is the managing member of Salisbury Investment Holdings, LLC and the holdings of Mr. Rady indicated above include both the direct personal holdings of Mr. Rady and the holdings of Salisbury Investment Holdings, LLC.

(8) Mr. Warren, our President, Chief Financial Officer and Secretary and one of our directors, is the managing member of Canton Investment Holdings, LLC and the holdings of Mr. Warren indicated above include both the direct personal holdings of Mr. Warren and the holdings of Canton Investment Holdings, LLC.

* Less than one percent.

DESCRIPTION OF NOTES

We will issue the new Notes under an indenture dated as of November 17, 2009 (the "Indenture"), among us, the Parent Guarantor, the Subsidiary Guarantors and Wells Fargo Bank, National Association, as trustee (the "Trustee"). On November 17, 2009, we issued $375 million principal amount of Notes under the Indenture. On January 19, 2010, we issued an additional $150 million principal amount of Notes, which are Additional Notes (as defined below) under the Indenture, which are treated together with the previously issued Notes as a single series of debt securities. References to the "Notes" in this "Description of Notes" include both the outstanding Notes and the Notes offered hereby. References in this "Description of Notes" to "Issue Date" mean November 17, 2009, the date on which the initial Notes were issued. The terms of the Notes include those expressly set forth in the Indenture and those made part of the Indenture by reference to the Trust Indenture Act of 1939, as amended (the "Trust Indenture Act"). The Indenture is unlimited in aggregate principal amount. We may issue an unlimited principal amount of additional Notes having identical terms and conditions as the Notes (the "Additional Notes"). We will only be permitted to issue such Additional Notes in compliance with the covenant described under the subheading "—Certain Covenants—Limitation on Indebtedness and Preferred Stock." Any Additional Notes will be part of the same series as the Notes that will vote on all matters with the holders of the Notes. Unless the context otherwise requires, for all purposes of the Indenture and this "Description of Notes," references to the Notes include the new Notes and the old Notes and any Additional Notes actually issued.

This "Description of Notes" is intended to be a useful overview of the material provisions of the Notes and the Indenture. Since this description is only a summary, you should refer to these documents for a complete description of the obligations of the Issuer and the Guarantors and your rights. A copy of the Indenture has been filed as an exhibit to the registration statement of which the prospectus is a part.

You will find the definitions of capitalized terms used in this "Description of Notes" under the heading "—Certain Definitions." For purposes of this description, references to "the Issuer," "we," "our" and "us" refer only to Antero Resources Finance Corporation, the issuer of the Notes, and references to "the Parent Guarantor" refer only to Antero Resources LLC and not to any of its subsidiaries.

The registered holder of a new Note will be treated as the owner of it for all purposes. Only registered holders of the Notes have rights under the Indenture, and all references to "holders" in this description are to registered holders of the Notes.

If the exchange offer contemplated by this prospectus is consummated, holders of old Notes who do not exchange those Notes for new Notes in the exchange offer will vote together with holders of new Notes for all relevant purposes under the Indenture. In that regard, the Indenture requires that certain actions by the holders thereunder must be taken, and certain rights must be exercised, by specified minimum percentages of the aggregate principal amount of the outstanding securities issued under the Indenture. In determining whether holders of the requisite percentage in principal amount have given any notice, consent or waiver or taken any other action permitted under the Indenture, any old Notes that remain outstanding after the exchange offer will be aggregated with the new Notes, and the holders of such old Notes and the new Notes will vote together as a single class for all such purposes. Accordingly, all references herein to specified percentages in aggregate principal amount of the Notes outstanding shall be deemed to mean, at any time after the exchange offer is consummated, such percentages in aggregate principal amount of the old Notes and the new Notes then outstanding.

General

The New Notes. The new Notes:

- will be general unsecured, senior obligations of the Issuer;
- will mature on December 1, 2017;
- will be issued in denominations of $2,000 and integral multiples of $1,000 in excess of $2,000;
- will be represented by one or more registered Notes in global form, but in certain circumstances may be represented by Notes in definitive form, see "—Book-Entry; Delivery and Form";
- will rank senior in right of payment to any future Subordinated Obligations of the Issuer;
- will rank equally in right of payment to any other senior Indebtedness of the Issuer (including the Issuer's guarantee under the Senior Secured Credit Agreement), without giving effect to collateral arrangements;
- will be initially unconditionally guaranteed on a senior unsecured basis by the Parent Guarantor and each current wholly-owned Subsidiary of the Parent Guarantor, see "—Guarantees"; and
- will effectively rank junior to any future secured Indebtedness of the Issuer, to the extent of the value of the collateral securing such Indebtedness.

The Guarantees. Initially, the Parent Guarantor and all of its wholly-owned Subsidiaries (other than the Issuer) will unconditionally guarantee the new Notes on a senior unsecured basis. Each Guarantee of the new Notes:

- will be general unsecured, senior obligations of the Guarantor;
- will rank senior in right of payment to any future Guarantor Subordinated Obligations of the Guarantor;
- will rank equally in right of payment to any other existing and future senior Indebtedness of the Guarantor, without giving effect to collateral arrangements;
- will effectively rank junior to all existing and future secured Indebtedness of the Guarantor, including any borrowings and guarantees under the Senior Secured Credit Agreement, to the extent of the value of the collateral securing such Indebtedness; and
- will effectively rank junior to all future Indebtedness of any non-guarantor Subsidiary of the Guarantor.

Currently, all of the Subsidiaries of the Parent Guarantor are Subsidiary Guarantors (except for the Issuer and Centrahoma Processing LLC, a 60% owned Subsidiary), and all of the Subsidiaries of the Parent Guarantor (including Centrahoma Processing LLC) are Restricted Subsidiaries. Certain future Subsidiaries of the Parent Guarantor may not be required to guarantee the Notes. See "—Certain Covenants—Future Subsidiary Guarantors." Also, under the circumstances described below in the definition of "Unrestricted Subsidiary" under the heading "—Certain Definitions," the Parent Guarantor may designate certain of its Subsidiaries as "Unrestricted Subsidiaries." Unrestricted Subsidiaries will not guarantee the Notes and will not be subject to the restrictive covenants in the Indenture. As of December 31, 2009, the only non-guaranteeing Subsidiary, Centrahoma Processing LLC, had no outstanding Indebtedness and held less than 4% of the Parent Guarantor's consolidated total assets.

Interest. Interest on the new Notes will:

- accrue at the rate of 9.375% per annum;

- accrue from the Issue Date or, if interest has already been paid on the Notes, from the most recent interest payment date;
- be payable in cash semi-annually in arrears on June 1 and December 1, commencing on June 1, 2010;
- be payable to the holders of record on the May 15 and November 15 immediately preceding the related interest payment dates; and
- be computed on the basis of a 360-day year comprised of twelve 30-day months.

If an interest payment date falls on a day that is not a Business Day, the interest payment to be made on such interest payment date will be made on the next succeeding Business Day with the same force and effect as if made on such interest payment date, and no additional interest will accrue as a result of such delayed payment. The Issuer will pay interest on overdue principal of the new Notes at the above rate, and overdue installments of interest at such rate, to the extent lawful.

Payments on the Notes; Paying Agent and Registrar

We will pay principal of, premium, if any, and interest on the Notes at the office or agency designated by us in the City and State of New York, except that we may, at our option, pay interest on the Notes by check mailed to holders of the Notes at their registered address as it appears in the registrar's books. We have initially designated the corporate trust office of the Trustee in Minneapolis, Minnesota to act as our paying agent and its corporate trust office in Dallas, Texas to act as registrar. We may, however, change the paying agent or registrar without prior notice to the holders of the Notes, and the Parent Guarantor or any of its Restricted Subsidiaries may act as paying agent or registrar.

We will pay principal of, premium, if any, and interest on, Notes in global form registered in the name of or held by The Depository Trust Company or its nominee in immediately available funds to The Depository Trust Company or its nominee, as the case may be, as the registered holder of such global Note.

Transfer and Exchange

A holder may transfer or exchange Notes in accordance with the Indenture. The registrar and the Trustee may require a holder, among other things, to furnish appropriate endorsements and transfer documents in connection with a transfer of Notes. No service charge will be imposed by the Issuer, the Trustee or the registrar for any registration of transfer or exchange of Notes, but the Issuer may require a holder to pay a sum sufficient to cover any transfer tax or other governmental taxes and fees required by law or permitted by the Indenture. The Issuer is not required to transfer or exchange any Note selected for redemption. Also, the Issuer is not required to transfer or exchange any Note for a period of 15 days before a selection of Notes to be redeemed.

The registered holder of a Note will be treated its owner for all purposes.

Optional Redemption

On and after December 1, 2013, we may redeem all or, from time to time, a part of the Notes upon not less than 30 nor more than 60 days' notice, at the following redemption prices (expressed as a percentage of principal amount of the Notes), plus accrued and unpaid interest on the Notes, if any, to the applicable redemption date (subject to the right of holders of record on the relevant record date to receive interest due on the relevant interest payment date), if redeemed during the 12-month period beginning on December 1 of the years indicated below:

Year	Percentage
2013	104.688%
2014	102.344%
2015 and thereafter	100.000%

On or prior to December 1, 2012, we may, at our option, on any one or more occasions redeem up to 35% of the aggregate principal amount of the Notes (including Additional Notes) issued under the Indenture with the Net Cash Proceeds of one or more Equity Offerings at a redemption price of 109.375% of the principal amount thereof, plus accrued and unpaid interest, if any, to the redemption date (subject to the right of holders of record on the relevant record date to receive interest due on the relevant interest payment date); *provided* that

(1) at least 65% of the aggregate principal amount of the Notes (including Additional Notes) issued under the Indenture remains outstanding after each such redemption; and

(2) the redemption occurs within 180 days after the closing of the related Equity Offering.

In addition, the Notes may be redeemed, in whole or in part, at any time prior to December 1, 2013 at the option of the Issuer upon not less than 30 nor more than 60 days' prior notice mailed by first-class mail to each holder of Notes at its registered address, at a redemption price equal to 100% of the principal amount of the Notes redeemed plus the Applicable Premium as of, and accrued and unpaid interest to, the applicable redemption date (subject to the right of holders of record on the relevant record date to receive interest due on the relevant interest payment date).

"Applicable Premium" means, with respect to any Note on any applicable redemption date, the greater of:

(1) 1.0% of the principal amount of such Note; or

(2) the excess, if any, of:

(a) the present value at such redemption date of (i) the redemption price of such Note at December 1, 2013 (such redemption price being set forth in the table appearing in the first paragraph of this "Optional redemption" section) plus (ii) all required interest payments (excluding accrued and unpaid interest to such redemption date) due on such Note through December 1, 2013 computed using a discount rate equal to the Treasury Rate as of such redemption date plus 50 basis points; over

(b) the principal amount of such Note.

"Treasury Rate" means, as of any redemption date, the yield to maturity at the time of computation of United States Treasury securities with a constant maturity (as compiled and published in the most recent Federal Reserve Statistical Release H.15 (519) which has become publicly available at least two Business Days prior to the redemption date (or, if such Statistical Release is no longer published, any publicly available source of similar market data)) most nearly equal to the period from the redemption date to December 1, 2013; *provided*, *however*, that if the period from the redemption date to December 1, 2013 is not equal to the constant maturity of a United States Treasury security for which a weekly average yield is given, the Treasury Rate shall be obtained by linear interpolation (calculated to the nearest one-twelfth of a year) from the weekly average yields of United States Treasury securities for which such yields are given, except that if the period from the redemption date to December 1, 2013 is less than one year, the weekly average yield on actually traded United States Treasury securities adjusted to a constant maturity of one year shall be used. The Issuer will (a) calculate the Treasury Rate as of the second Business Day preceding the applicable redemption date and (b) prior to such redemption date file with the Trustee an Officers' Certificate setting forth the Applicable Premium and the Treasury Rate and showing the calculation of each in reasonable detail.

Selection and Notice

If the Issuer is redeeming less than all of the outstanding Notes, the Trustee will select the Notes for redemption in compliance with the requirements of the principal national securities exchange, if any, on which the Notes are listed or, if the Notes are not listed, then on a pro rata basis, by lot or by such other method as the Trustee in its sole discretion will deem to be fair and appropriate, although no Note of $2,000 in original principal amount or less will be redeemed in part. If any Note is to be redeemed in part only, the notice of redemption relating to such Note will state the portion of the principal amount thereof to be redeemed. A new Note in principal amount equal to the unredeemed portion thereof will be issued in the name of the holder thereof upon cancellation of the partially redeemed Note. On and after the redemption date, interest will cease to accrue on Notes or the portion of them called for redemption unless we default in the payment thereof.

Mandatory Redemption; Offers to Purchase; Open Market Purchases

We are not required to make mandatory redemption payments or sinking fund payments with respect to the Notes. However, under certain circumstances, we may be required to offer to purchase Notes as described under the captions "—Change of Control" and "—Certain Covenants—Limitation on Sales of Assets and Subsidiary Stock."

The Parent Guarantor and its Subsidiaries may acquire Notes by means other than a redemption or required repurchase, whether by tender offer, open market purchases, negotiated transactions or otherwise, in accordance with applicable securities laws, so long as such acquisition does not otherwise violate the terms of the Indenture. However, other existing or future agreements of the Parent Guarantor or its Subsidiaries may limit the ability of the Parent Guarantor or its Subsidiaries to purchase Notes prior to maturity.

Ranking

The new Notes, like the old Notes, will be general unsecured obligations of the Issuer that rank senior in right of payment to any of its future Indebtedness that is expressly subordinated in right of payment to the Notes. The new Notes will rank equally in right of payment with all other Indebtedness of the Issuer that is not so subordinated and will be effectively subordinated to any of its future secured Indebtedness, to the extent of the value of the collateral securing such Indebtedness.

The obligations of each of the Guarantors under the Guarantees for the Notes will rank equally in right of payment with all other Indebtedness of such Guarantor, except to the extent such other Indebtedness is expressly subordinated in right of payment to the obligations arising under its Guarantee. However, such obligations will effectively rank junior to all existing and future secured Indebtedness of the Guarantors (including any borrowings and guarantees under the Senior Secured Credit Agreement), to the extent of the value of the collateral securing such Indebtedness. In the event of bankruptcy, liquidation, reorganization or other winding up of the Parent Guarantor or the Subsidiary Guarantors, or upon a default in payment with respect to, or the acceleration of, any Indebtedness under the Senior Secured Credit Agreement or other secured Indebtedness, the assets of the Parent Guarantor and the Subsidiary Guarantors that secure secured Indebtedness will be available to pay obligations on the Notes and the Guarantees only after all Indebtedness under the Senior Secured Credit Agreement and other secured Indebtedness has been repaid in full from such assets. In addition, in the event of bankruptcy, liquidation, reorganization or other winding up of a non-guarantor Subsidiary, the assets of such Subsidiary will be available to pay obligations on the Notes and the

Guarantees only after all obligations of such Subsidiary have been repaid in full from such assets. We advise you that there may not be sufficient assets remaining to pay amounts due on any or all the Notes and the Guarantees then outstanding.

As of March 31, 2010:

- we, the Parent Guarantor and the Subsidiary Guarantors had approximately $529 million of total Indebtedness (excluding Hedging Obligations and letters of credit outstanding under the Senior Secured Credit Agreement); and
- of the $529 million of such total Indebtedness, none constituted secured Indebtedness under the Senior Secured Credit Agreement, but letters of credit aggregating approximately $11 million were outstanding thereunder, as to which the Subsidiary Guarantees were effectively subordinated to the extent of the value of the collateral securing such Indebtedness, and the Subsidiary Guarantors had additional availability of approximately $358 million under the Senior Secured Credit Agreement.

Guarantees

The Parent Guarantor and the Subsidiary Guarantors have, jointly and severally, fully and unconditionally guaranteed on a senior unsecured basis our obligations under the Notes and all obligations under the Indenture. The obligations of each of the Guarantors under the Guarantees rank equally in right of payment with all other Indebtedness of such Guarantor, except to the extent such other Indebtedness is expressly subordinated in right of payment to the obligations arising under its Guarantee.

As of March 31, 2010, the Guarantors had approximately $529 million of total Indebtedness (excluding Hedging Obligations and letters of credit outstanding under the Senior Secured Credit Agreement), consisting of capital leases of approximately $1 million and unsecured guarantees of $528 million under the Notes.

Although the Indenture limits the amount of Indebtedness that the Parent Guarantor and its Restricted Subsidiaries may Incur, such Indebtedness may be substantial and such limitation is subject to a number of significant qualifications. Moreover, the Indenture does not impose any limitation on the Incurrence by such Persons of liabilities that are not considered Indebtedness under the Indenture. See "—Certain Covenants—Limitation on Indebtedness and Preferred Stock."

The obligations of each Guarantor under its Guarantee will be limited as necessary to prevent that Guarantee from constituting a fraudulent conveyance or fraudulent transfer under applicable law, although no assurance can be given that a court would give the holder the benefit of such provision. See "Risk Factors—Risks Relating to Investment in the Notes—Any guarantees of the notes by Antero or the operating subsidiaries could be deemed fraudulent conveyances under certain circumstances, and a court may subordinate or void the guarantees." If a Guarantee were rendered voidable, it could be subordinated by a court to all other indebtedness (including guarantees and other contingent liabilities) of the applicable Guarantor, and, depending on the amount of such indebtedness, a Guarantor's liability on its Guarantee could be reduced to zero. If the obligations of a Guarantor under its Guarantee were avoided, holders of Notes would have to look to the assets of any remaining Guarantors for payment. There can be no assurance in that event that such assets would suffice to pay the outstanding principal and interest on the Notes.

In the event a Subsidiary Guarantor is sold or disposed of (whether by merger, consolidation, the sale of its Capital Stock or the sale of all or substantially all of its assets (other than by lease)) and whether or not the Subsidiary Guarantor is the surviving entity in such transaction to a Person which is not the Parent Guarantor or a Restricted Subsidiary of the Parent Guarantor, such Subsidiary Guarantor will be released from its obligations under its Subsidiary Guarantee if the sale or other disposition does not violate the covenants described under "—Certain Covenants—Limitation on Sales of Assets and Subsidiary Stock."

In addition, a Subsidiary Guarantor will be released from its obligations under the Indenture and its Subsidiary Guarantee, upon the release or discharge of the guarantee of other Indebtedness that resulted in the creation of such Subsidiary Guarantee pursuant to clause (b) of the covenant described under "—Certain Covenants—Future Subsidiary Guarantors," except a release or discharge by or as a result of payment under such guarantee; if the Parent Guarantor designates such Subsidiary as an Unrestricted Subsidiary and such designation complies with the other applicable provisions of the Indenture or in connection with any covenant defeasance, legal defeasance or satisfaction and discharge of the Notes as provided below under the captions "—Defeasance" and "—Satisfaction and Discharge." The Parent Guarantor will be released from its obligations under the Indenture and the Parent Guarantee only in connection with any such legal defeasance or satisfaction and discharge of the Notes.

Change of Control

If a Change of Control occurs, unless the Issuer has previously or concurrently exercised its right to redeem all of the Notes as described under "—Optional Redemption," each holder will have the right to require the Issuer to repurchase all or any part (equal to $2,000 or an integral multiple of $1,000 in excess of $2,000) of such holder's Notes at a purchase price in cash equal to 101% of the principal amount of the Notes plus accrued and unpaid interest, if any, to the date of purchase (subject to the right of holders of record on the relevant record date to receive interest due on the relevant interest payment date).

Within 30 days following any Change of Control, unless we have previously or concurrently exercised our right to redeem all of the Notes as described under "—Optional Redemption," we will mail a notice (the "Change of Control Offer") to each holder, with a copy to the Trustee, stating:

(1) that a Change of Control has occurred and that such holder has the right to require us to purchase such holder's Notes at a purchase price in cash equal to 101% of the principal amount of such Notes plus accrued and unpaid interest, if any, to the date of purchase (subject to the right of holders of record on a record date to receive interest on the relevant interest payment date) (the "Change of Control Payment");

(2) the repurchase date (which shall be no earlier than 30 days nor later than 60 days from the date such notice is mailed) (the "Change of Control Payment Date");

(3) that any Note not properly tendered will remain outstanding and continue to accrue interest;

(4) that unless we default in the payment of the Change of Control Payment, all Notes accepted for payment pursuant to the Change of Control Offer will cease to accrue interest on the Change of Control Payment Date;

(5) that holders electing to have any Notes purchased pursuant to a Change of Control Offer will be required to surrender such Notes, with the form entitled "Option of Holder to Elect Purchase" on the reverse of such Notes in certificated form completed, to the paying agent specified in the notice at the address specified in the notice prior to the close of business on the third Business Day preceding the Change of Control Payment Date;

(6) that holders will be entitled to withdraw their tendered Notes and their election to require us to purchase such Notes, provided that the paying agent receives, not later than the close of business on the third Business Day preceding the Change of Control Payment Date, a telegram, telex, facsimile transmission or letter setting forth the name of the holder of the Notes, the principal amount of Notes tendered for purchase, and a statement that such holder is withdrawing its tendered Notes and its election to have such Notes purchased;

(7) that if we are repurchasing a portion of the Note of any holder, the holder will be issued a new Note equal in principal amount to the unpurchased portion of the Note surrendered, *provided* that the unpurchased portion of the Note must be equal to a minimum principal amount of $2,000 and an integral multiple of $1,000 in excess of $2,000; and

(8) the procedures determined by us, consistent with the Indenture, that a holder must follow in order to have its Notes repurchased.

On the Change of Control Payment Date, the Issuer will, to the extent lawful:

(1) accept for payment all Notes or portions of Notes (in a minimum principal amount of $2,000 and integral multiples of $1,000 in excess of $2,000) properly tendered pursuant to the Change of Control Offer and not properly withdrawn;

(2) deposit with the paying agent an amount equal to the Change of Control Payment in respect of all Notes or portions of Notes accepted for payment; and

(3) deliver or cause to be delivered to the Trustee the Notes so accepted together with an Officers' Certificate stating the aggregate principal amount of Notes or portions of Notes being purchased by the Issuer.

The paying agent will promptly mail or deliver to each holder of Notes accepted for payment the Change of Control Payment for such Notes, and the Trustee will promptly authenticate and mail (or cause to be transferred by book entry) to each holder a new Note equal in principal amount to any unpurchased portion of the Notes surrendered, if any; *provided* that each such new Note will be in a minimum principal amount of $2,000 or an integral multiple of $1,000 in excess of $2,000.

If the Change of Control Payment Date is on or after an interest record date and on or before the related interest payment date, any accrued and unpaid interest, will be paid to the Person in whose name a Note is registered at the close of business on such record date, and no further interest will be payable to holders who tender pursuant to the Change of Control Offer.

The Change of Control provisions described above will be applicable whether or not any other provisions of the Indenture are applicable. Except as described above with respect to a Change of Control, the Indenture does not contain provisions that permit the holders to require that the Parent Guarantor or any Subsidiary repurchase or redeem the Notes in the event of a takeover, recapitalization or similar transaction.

We will not be required to make a Change of Control Offer upon a Change of Control if the Parent Guarantor or any other Person makes the Change of Control Offer in the manner, at the times and otherwise in compliance with the requirements set forth in the Indenture applicable to a Change of Control Offer made by us and purchases all Notes validly tendered and not withdrawn under such Change of Control Offer.

A Change of Control Offer may be made in advance of a Change of Control, and conditioned upon the occurrence of a Change of Control, if a definitive agreement is in place for the Change of Control at the time of making the Change of Control Offer.

We will comply, to the extent applicable, with the requirements of Rule 14e-1 of the Exchange Act and any other securities laws or regulations in connection with the repurchase of Notes as a result of a Change of Control. To the extent that the provisions of any securities laws or regulations conflict with provisions of this covenant, we will comply with the applicable securities laws and regulations and will not be deemed to have breached our obligations under in the Indenture by virtue of our compliance with such securities laws or regulations.

Our ability to repurchase Notes pursuant to a Change of Control Offer may be limited by a number of factors. The occurrence of certain of the events that constitute a Change of Control would constitute a default under the Senior Secured Credit Agreement. In addition, certain events that may constitute a change of control under the Senior Secured Credit Agreement and cause a default under that agreement will not constitute a Change of Control under the Indenture. Future Indebtedness of the Parent Guarantor and its Subsidiaries may also contain prohibitions of certain events that would constitute a Change of Control or require such Indebtedness to be repaid upon a Change of Control. Moreover, the exercise by the holders of their right to require the Issuer to repurchase the Notes could cause a default under such Indebtedness, even if the Change of Control itself does not, due to the financial effect of such repurchase on the Parent Guarantor and its Restricted Subsidiaries. Finally, the Issuer's ability to pay cash to the holders upon a repurchase may be limited by the then existing financial resources of the Parent Guarantor and its Restricted Subsidiaries. There can be no assurance that sufficient funds will be available when necessary to make any required repurchases.

Even if sufficient funds were otherwise available, the future Indebtedness of the Parent Guarantor or its Restricted Subsidiaries may prohibit the Issuer's repurchase of Notes before their scheduled maturity. Consequently, if the Parent Guarantor and its Restricted Subsidiaries are not able to prepay the Indebtedness under the Senior Secured Credit Agreement and any such other Indebtedness containing similar restrictions or obtain requisite consents, the Issuer will be unable to fulfill its repurchase obligations if holders of Notes exercise their repurchase rights following a Change of Control, resulting in a default under the Indenture. A default under the Indenture may result in a cross-default under the Senior Secured Credit Agreement.

If holders of not less than 90% in aggregate principal amount of the outstanding Notes validly tender and do not withdraw such Notes in a Change of Control Offer and the Issuer, or any other Person making a Change of Control Offer in lieu of the Issuer as described above, purchases all of the Notes validly tendered and not withdrawn by such holders, the Issuer will have the right, upon not less than 30 nor more than 60 days' prior notice, given not more than 30 days following such purchase pursuant to the Change of Control Offer described above, to redeem all Notes that remain outstanding following such purchase at a redemption price in cash equal to the applicable Change of Control Payment plus, to the extent not included in the Change of Control Payment, accrued and unpaid interest, if any, to the date of redemption (subject to the right of holders of record on the relevant record date to receive interest due on the relevant interest payment date).

The Change of Control provisions described above may deter certain mergers, tender offers and other takeover attempts involving the Parent Guarantor. The Change of Control purchase feature is a result of negotiations between the initial purchasers and the Parent Guarantor. As of the Issue Date, the Parent Guarantor has no present intention to engage in a transaction involving a Change of Control, although it is possible that it could decide to do so in the future. Subject to the limitations discussed below, the Parent Guarantor or its Subsidiaries could, in the future, enter into certain transactions, including acquisitions, refinancings or other recapitalizations, that would not constitute a Change of Control under the Indenture, but that could increase the amount of indebtedness outstanding at such time or otherwise affect our capital structure or credit ratings. Restrictions on the ability of the Parent Guarantor and its Restricted Subsidiaries to incur additional Indebtedness are contained in the covenants described under "—Certain Covenants—Limitation on Indebtedness and Preferred Stock" and "—Certain Covenants—Limitation on Liens." Such restrictions in the Indenture can be waived only with the consent of the holders of a majority in principal amount of the Notes then outstanding. Except for the limitations contained in such covenants, however, the Indenture does not contain any covenants or provisions that may afford holders of the Notes protection in the event of a highly leveraged transaction.

The definition of "Change of Control" includes a disposition of all or substantially all of the assets of the Parent Guarantor and its Restricted Subsidiaries taken as a whole to any Person. Although there is a limited body of case law interpreting the phrase "substantially all," there is no precise established definition of the phrase under applicable law. Accordingly, in certain circumstances there may be a degree of uncertainty as to whether a particular transaction would involve a disposition of "all or substantially all" of the assets of a Person. As a result, it may be unclear as to whether a Change of Control has occurred and whether a holder of Notes may require the Issuer to make an offer to repurchase the Notes as described above. In a recent decision, the Chancery Court of Delaware raised the possibility that a Change of Control occurring as a result of a failure to have Continuing Directors comprising a majority of the Board of Directors may be unenforceable on public policy grounds.

The provisions under the Indenture relative to our obligation to make an offer to repurchase the Notes as a result of a Change of Control may be waived or modified or terminated with the consent of the holders of a majority in principal amount of the Notes then outstanding (including consents obtained in connection with a tender offer or exchange offer for the Notes) prior to the occurrence of such Change of Control.

Certain Covenants

Limitation on Indebtedness and Preferred Stock

The Parent Guarantor will not, and will not permit any of its Restricted Subsidiaries to, directly or indirectly, Incur any Indebtedness (including Acquired Indebtedness) and the Parent Guarantor will not permit any of its Restricted Subsidiaries to issue Preferred Stock; *provided*, *however*, that the Parent Guarantor may Incur Indebtedness and any of the Subsidiary Guarantors may Incur Indebtedness and issue Preferred Stock if on the date thereof:

(1) the Consolidated Coverage Ratio for the Parent Guarantor and its Restricted Subsidiaries is at least 2.25 to 1.00, determined on a pro forma basis (including a pro forma application of proceeds); and

(2) no Default would occur as a consequence of, and no Event of Default would be continuing following, Incurring the Indebtedness or its application.

The first paragraph of this covenant will not prohibit the Incurrence of the following Indebtedness:

(1) Indebtedness under one or more Credit Facilities of (a) the Parent Guarantor, the Issuer or any Subsidiary Guarantor Incurred pursuant to this clause (1) in an aggregate amount not to exceed the greater of (i) $500.0 million or (ii) the sum of $250.0 million and 30.0% of the Parent Guarantor's Adjusted Consolidated Net Tangible Assets determined as of the date of the Incurrence of such Indebtedness after giving effect to the application of the proceeds therefrom and (b) any Foreign Subsidiary Incurred pursuant to this clause (1) in an aggregate amount not to exceed $30.0 million, in each case outstanding at any one time;

(2) guarantees of Indebtedness Incurred in accordance with the provisions of the Indenture; *provided* that in the event such Indebtedness that is being guaranteed is a Subordinated Obligation or a Guarantor Subordinated Obligation, then the related guarantee shall be subordinated in right of payment to the Notes or the Guarantee to at least the same extent as the Indebtedness being guaranteed, as the case may be;

(3) Indebtedness of the Parent Guarantor owing to and held by any Restricted Subsidiary or Indebtedness of a Restricted Subsidiary owing to and held by the Parent Guarantor or any Restricted Subsidiary; *provided*, *however*, that (a)(i) if the Parent Guarantor is the obligor on such Indebtedness and the obligee is not a Subsidiary Guarantor, such Indebtedness must be expressly subordinated to the prior payment in full in cash of all obligations with respect to the Notes and (ii) if a Subsidiary Guarantor is the obligor of such Indebtedness and the obligee is neither the Parent Guarantor nor a Subsidiary Guarantor, such Indebtedness must be expressly subordinated to the prior payment in full in cash of all obligations of such Subsidiary Guarantor with respect to its Subsidiary Guarantee and (b)(i) any subsequent

issuance or transfer of Capital Stock or any other event which results in any such Indebtedness being held by a Person other than the Parent Guarantor or a Restricted Subsidiary of the Parent Guarantor and (ii) any sale or other transfer of any such Indebtedness to a Person other than the Parent Guarantor or a Restricted Subsidiary of the Parent Guarantor shall be deemed, in each case, to constitute an Incurrence of such Indebtedness by the Parent Guarantor or such Subsidiary, as the case may be, that was not permitted by this clause;

(4) Indebtedness represented by (a) the Notes issued on the Issue Date and all Guarantees, (b) any Indebtedness (other than the Indebtedness described in clauses (1), (2) and 4(a)) outstanding on the Issue Date, (c) any Exchange Notes and related guarantees issued pursuant to a Registration Rights Agreement and (d) any Refinancing Indebtedness Incurred in respect of any Indebtedness described in this clause (4) or clause (5) or (7) or Incurred pursuant to the first paragraph of this covenant;

(5) Permitted Acquisition Indebtedness;

(6) Indebtedness Incurred in respect of (a) self-insurance obligations, bid, appeal, reimbursement, performance, surety and similar bonds and completion guarantees provided by the Parent Guarantor or a Restricted Subsidiary in the ordinary course of business and any guarantees or letters of credit functioning as or supporting any of the foregoing bonds or obligations and (b) obligations represented by letters of credit for the account of the Parent Guarantor or a Restricted Subsidiary in order to provide security for workers' compensation claims (in the case of clauses (a) and (b) other than for an obligation for money borrowed);

(7) Indebtedness of the Parent Guarantor or any Restricted Subsidiary represented by Capitalized Lease Obligations (whether or not incurred pursuant to Sale/Leaseback Transactions) or other Indebtedness incurred or assumed in connection with the acquisition, construction, improvement or development of real or personal, movable or immovable, property, in each case Incurred for the purpose of financing, refinancing, renewing, defeasing or refunding all or any part of the purchase price or cost of acquisition, construction, improvement or development of property used in the business of the Parent Guarantor or its Restricted Subsidiaries; *provided* that the aggregate principal amount incurred by the Parent Guarantor or any Restricted Subsidiary pursuant to this clause (7) outstanding at any time shall not exceed the greater of (x) \$15.0 million and (y) 1.5% of the Parent Guarantor's Adjusted Consolidated Net Tangible Assets; and *provided further* that the principal amount of any Indebtedness permitted under this clause (7) did not in each case at the time of incurrence exceed the Fair Market Value, as determined in accordance with the definition of such term, of the acquired or constructed asset or improvement so financed;

(8) Preferred Stock (other than Disqualified Stock) of any Restricted Subsidiary;

(9) Cash Management Obligations of the Issuer or any Guarantor in an aggregate amount not to exceed \$7.5 million outstanding at any one time; and

(10) in addition to the items referred to in clauses (1) through (9) above, Indebtedness of the Parent Guarantor and its Restricted Subsidiaries in an aggregate outstanding principal amount which, when taken together with the principal amount of all other Indebtedness Incurred pursuant to this clause (10) and then outstanding, will not exceed the greater of \$35.0 million or 2.5% of the Parent Guarantor's Adjusted Consolidated Net Tangible Assets, determined as of the date of Incurrence of such Indebtedness after giving effect to such Incurrence and the application of the proceeds therefrom.

For purposes of determining compliance with, and the outstanding principal amount of any particular Indebtedness Incurred pursuant to and in compliance with, this covenant:

(1) in the event an item of that Indebtedness meets the criteria of more than one of the types of Indebtedness described in the first and second paragraphs of this covenant, the Parent Guarantor, in its sole discretion, will classify such item of Indebtedness on the date of Incurrence and, subject to clause (2) below may later classify, reclassify or redivide all or a portion of such item of Indebtedness, in any manner that complies with this covenant;

(2) all Indebtedness outstanding on the date of the Indenture under the Senior Secured Credit Agreement shall be deemed Incurred on the Issue Date under clause (1) of the second paragraph of this covenant;

(3) guarantees of, or obligations in respect of letters of credit supporting, Indebtedness which is otherwise included in the determination of a particular amount of Indebtedness shall not be included;

(4) if obligations in respect of letters of credit are Incurred pursuant to a Credit Facility and are being treated as Incurred pursuant to clause (1) of the second paragraph above and the letters of credit relate to other Indebtedness, then such other Indebtedness shall not be included;

(5) the principal amount of any Disqualified Stock of the Parent Guarantor or a Restricted Subsidiary, or Preferred Stock of a Restricted Subsidiary that is not a Subsidiary Guarantor, will be equal to the greater of the maximum mandatory redemption or repurchase price (not including, in either case, any redemption or repurchase premium) or the liquidation preference thereof;

(6) Indebtedness permitted by this covenant need not be permitted solely by reference to one provision permitting such Indebtedness but may be permitted in part by one such provision and in part by one or more other provisions of this covenant permitting such Indebtedness; and

(7) the amount of Indebtedness issued at a price that is less than the principal amount thereof will be equal to the amount of the liability in respect thereof determined in accordance with GAAP.

Accrual of interest, accrual of dividends, the amortization of debt discount or the accretion of accreted value, the payment of interest in the form of additional Indebtedness, the payment of dividends in the form of additional shares of Preferred Stock or Disqualified Stock and unrealized losses or charges in respect of Hedging Obligations (including those resulting from the application of Statement of Financial Accounting Standard No. 133) will not be deemed to be an Incurrence of Indebtedness for purposes of this covenant.

The Parent Guarantor will not permit any of its Unrestricted Subsidiaries to Incur any Indebtedness, or issue any shares of Disqualified Stock, other than Non-Recourse Debt. If at any time an Unrestricted Subsidiary becomes a Restricted Subsidiary, any Indebtedness of such Subsidiary shall be deemed to be Incurred by a Restricted Subsidiary as of such date (and, if such Indebtedness is not permitted to be Incurred as of such date under this "Limitation on Indebtedness and Preferred Stock" covenant, the Parent Guarantor shall be in Default of this covenant).

For purposes of determining compliance with any U.S. dollar-denominated restriction on the Incurrence of Indebtedness, the U.S. dollar-equivalent principal amount of Indebtedness denominated in a foreign currency shall be calculated based on the relevant currency exchange rate in effect on the date such Indebtedness was Incurred, in the case of term Indebtedness, or first committed, in the case of revolving credit Indebtedness; *provided* that if such Indebtedness is Incurred to refinance other Indebtedness denominated in a foreign currency, and such refinancing would cause the applicable U.S.

dollar-denominated restriction to be exceeded if calculated at the relevant currency exchange rate in effect on the date of such refinancing, such U.S. dollar-denominated restriction shall be deemed not to have been exceeded so long as the principal amount of such refinancing Indebtedness does not exceed the principal amount of such Indebtedness being refinanced. Notwithstanding any other provision of this covenant, the maximum amount of Indebtedness that the Parent Guarantor may Incur pursuant to this covenant shall not be deemed to be exceeded solely as a result of fluctuations in the exchange rates of currencies. The principal amount of any Indebtedness Incurred to refinance other Indebtedness, if Incurred in a different currency from the Indebtedness being refinanced, shall be calculated based on the currency exchange rate applicable to the currencies in which such Refinancing Indebtedness is denominated that is in effect on the date of such refinancing.

The Indenture does not treat (1) unsecured Indebtedness as subordinated or junior to secured Indebtedness merely because it is unsecured or (2) senior Indebtedness as subordinated or junior to any other senior Indebtedness merely because it has a junior priority with respect to the same collateral.

Limitation on Restricted Payments

The Parent Guarantor will not, and will not permit any of its Restricted Subsidiaries, directly or indirectly, to:

(1) declare or pay any dividend or make any payment or distribution on or in respect of the Parent Guarantor's Capital Stock (including any payment or distribution in connection with any merger or consolidation involving the Parent Guarantor or any of its Restricted Subsidiaries) except:

(a) dividends or distributions by the Parent Guarantor payable solely in Capital Stock of the Parent Guarantor (other than Disqualified Stock but including options, warrants or other rights to purchase such Capital Stock of the Parent Guarantor); and

(b) dividends or distributions payable to the Parent Guarantor or a Restricted Subsidiary and if such Restricted Subsidiary is not a Wholly-Owned Subsidiary, to minority stockholders (or owners of an equivalent interest in the case of a Subsidiary that is an entity other than a corporation) so long as the Parent Guarantor or a Restricted Subsidiary receives at least its pro rata share of such dividend or distribution;

(2) purchase, repurchase, redeem, defease or otherwise acquire or retire for value any Capital Stock of the Parent Guarantor or any direct or indirect parent of the Parent Guarantor held by Persons other than the Parent Guarantor or a Restricted Subsidiary (other than in exchange for Capital Stock of the Parent Guarantor (other than Disqualified Stock));

(3) purchase, repurchase, redeem, defease or otherwise acquire or retire for value, prior to scheduled maturity, scheduled repayment or scheduled sinking fund payment, any Subordinated Obligations or Guarantor Subordinated Obligations (other than (x) Indebtedness permitted under clause (3) of the second paragraph of the covenant "—Limitation on Indebtedness and Preferred Stock" or (y) the purchase, repurchase, redemption, defeasance or other acquisition or retirement of Subordinated Obligations or Guarantor Subordinated Obligations purchased in anticipation of satisfying a sinking fund obligation, principal installment or final maturity, in each case due within one year of the date of purchase, repurchase, redemption, defeasance or other acquisition or retirement); or

(4) make any Restricted Investment in any Person;

(any such dividend, distribution, purchase, redemption, repurchase, defeasance, other acquisition, retirement or Restricted Investment referred to in clauses (1) through (4) shall be referred to herein as a "Restricted Payment"), if at the time the Parent Guarantor or such Restricted Subsidiary makes such Restricted Payment:

(a) a Default shall have occurred and be continuing (or would result therefrom);

(b) the Parent Guarantor is not able to Incur an additional $1.00 of Indebtedness pursuant to the covenant described under the first paragraph under "—Limitation on Indebtedness and Preferred Stock" after giving effect, on a pro forma basis, to such Restricted Payment; or

(c) the aggregate amount of such Restricted Payment and all other Restricted Payments declared or made subsequent to the Issue Date would exceed the sum of:

(i) 50% of Consolidated Net Income for the period (treated as one accounting period) from January 1, 2010 to the end of the most recent fiscal quarter ending prior to the date of such Restricted Payment for which internal financial statements are in existence (or, in case such Consolidated Net Income is a deficit, minus 100% of such deficit);

(ii) 100% of the aggregate Net Cash Proceeds and the Fair Market Value of property or securities other than cash (including Capital Stock of Persons engaged primarily in the Oil and Gas Business or assets used in the Oil and Gas Business), in each case received by the Parent Guarantor from the issue or sale of its Capital Stock (other than Disqualified Stock) or other capital contributions subsequent to the Issue Date (other than Net Cash Proceeds received from an issuance or sale of such Capital Stock to (x) management, employees, directors or any direct or indirect parent of the Parent Guarantor, to the extent such Net Cash Proceeds have been used to make a Restricted Payment pursuant to clause (5)(a) of the next succeeding paragraph, (y) a Subsidiary of the Parent Guarantor or (z) an employee stock ownership plan, option plan or similar trust (to the extent such sale to an employee stock ownership plan, option plan or similar trust is financed by loans from or Guaranteed by the Parent Guarantor or any Restricted Subsidiary unless such loans have been repaid with cash on or prior to the date of determination));

(iii) the amount by which Indebtedness of the Parent Guarantor or its Restricted Subsidiaries is reduced on the Parent Guarantor's balance sheet upon the conversion or exchange (other than by a Subsidiary of the Parent Guarantor) subsequent to the Issue Date of any Indebtedness of the Parent Guarantor or its Restricted Subsidiaries convertible or exchangeable for Capital Stock (other than Disqualified Stock) of the Parent Guarantor (less the amount of any cash, or the Fair Market Value of any other property (other than such Capital Stock), distributed by the Parent Guarantor upon such conversion or exchange), together with the net proceeds, if any, received by the Parent Guarantor or any of its Restricted Subsidiaries upon such conversion or exchange; and

(iv) the amount equal to the aggregate net reduction in Restricted Investments made by the Parent Guarantor or any of its Restricted Subsidiaries in any Person after the Issue Date resulting from:

(A) repurchases, repayments or redemptions of such Restricted Investments by such Person, proceeds realized upon the sale of such Restricted Investment (other than to a Subsidiary of the Parent Guarantor), repayments of loans or advances or other transfers of assets (including by way of dividend or distribution) by such Person to the Parent Guarantor or any Restricted Subsidiary;

(B) the redesignation of Unrestricted Subsidiaries as Restricted Subsidiaries (valued in each case as provided in the definition of "Investment") not to exceed, in the case of any Unrestricted Subsidiary, the amount of Investments previously made by the Parent Guarantor or any Restricted Subsidiary in such Unrestricted Subsidiary, which amount in each case under this clause (iv) was included in the calculation of the amount of Restricted Payments; *provided*, *however*, that no amount will be included under this clause (iv) to the extent it is already included in Consolidated Net Income; and

(C) the sale by the Parent Guarantor or any Restricted Subsidiary (other than to the Parent Guarantor or a Restricted Subsidiary) of all or a portion of the Capital Stock of an Unrestricted Subsidiary or a distribution from an Unrestricted Subsidiary or a dividend from an Unrestricted Subsidiary (whether any such distribution or dividend is made with proceeds from the issuance by such Unrestricted Subsidiary of its Capital Stock or otherwise).

The provisions of the preceding paragraph will not prohibit:

(1) any Restricted Payment made by exchange for, or out of the proceeds of the substantially concurrent sale of, Capital Stock of the Parent Guarantor (other than Disqualified Stock and other than Capital Stock issued or sold to a Subsidiary of the Parent Guarantor or an employee stock ownership plan or similar trust to the extent such sale to an employee stock ownership plan or similar trust is financed by loans from or Guaranteed by the Parent Guarantor or any Restricted Subsidiary unless such loans have been repaid with cash on or prior to the date of determination) or a substantially concurrent cash capital contribution received by the Parent Guarantor from its shareholders; *provided*, *however*, that (a) such Restricted Payment will be excluded from subsequent calculations of the amount of Restricted Payments and (b) the Net Cash Proceeds from such sale of Capital Stock or capital contribution will be excluded from clause (c)(ii) of the preceding paragraph;

(2) any purchase, repurchase, redemption, defeasance or other acquisition or retirement of Subordinated Obligations of the Issuer or Guarantor Subordinated Obligations of any Guarantor made by exchange for, or out of the proceeds of the substantially concurrent sale of, Subordinated Obligations of the Issuer or any purchase, repurchase, redemption, defeasance or other acquisition or retirement of Guarantor Subordinated Obligations made by exchange for or out of the proceeds of the substantially concurrent sale of Guarantor Subordinated Obligations that, in each case, is permitted to be Incurred pursuant to the covenant described under "—Limitation on Indebtedness and Preferred Stock"; *provided*, *however*, that such purchase, repurchase, redemption, defeasance, acquisition or retirement will be excluded from subsequent calculations of the amount of Restricted Payments;

(3) any purchase, repurchase, redemption, defeasance or other acquisition or retirement of Disqualified Stock of the Parent Guarantor or a Restricted Subsidiary made by exchange for, or out of the proceeds of the substantially concurrent sale of, Disqualified Stock of the Parent Guarantor or such Restricted Subsidiary, as the case may be, that, in each case, is permitted to be Incurred pursuant to the covenant described under "—Limitation on Indebtedness and Preferred Stock"; *provided*, *however*, that such purchase, repurchase, redemption, defeasance, acquisition or retirement will be excluded from subsequent calculations of the amount of Restricted Payments;

(4) dividends paid or distributions made within 60 days after the date of declaration if at such date of declaration such dividend or distribution would have complied with this covenant; *provided*, *however*, that such dividends and distributions will be included in subsequent calculations of the amount of Restricted Payments; and *provided further*, *however*, that for purposes of clarification, this clause (4) shall not include cash payments in lieu of the issuance of fractional shares included in clause (9) below;

(5) so long as no Default has occurred and is continuing, (a) the repurchase or other acquisition of Capital Stock (including options, warrants, equity appreciation rights or other rights to purchase or acquire Capital Stock) of the Parent Guarantor held by any existing or former employees, management or directors of the Parent Guarantor or any Restricted Subsidiary of the Parent Guarantor or their assigns, estates or heirs, in each case pursuant to the repurchase or other acquisition provisions under employee stock option or stock purchase plans or

agreements or other agreements to compensate management, employees or directors, in each case approved by the Parent Guarantor's Board of Directors; *provided* that such repurchases or other acquisitions pursuant to this subclause (a) during any calendar year will not exceed $2.0 million in the aggregate (with unused amounts in any calendar year being carried over to succeeding calendar years); *provided further*, that such amount in any calendar year may be increased by an amount not to exceed (A) the cash proceeds received by the Parent Guarantor from the sale of Capital Stock of the Parent Guarantor to members of management or directors of the Parent Guarantor and its Restricted Subsidiaries that occurs after the Issue Date (to the extent the cash proceeds from the sale of such Capital Stock have not otherwise been applied to the payment of Restricted Payments by virtue of the clause (c) of the preceding paragraph), plus (B) the cash proceeds of key man life insurance policies received by the Parent Guarantor and its Restricted Subsidiaries after the Issue Date, less (C) the amount of any Restricted Payments made pursuant to clauses (A) and (B) of this clause (5)(a); *provided further*, however, that the amount of any such repurchase or other acquisition under this subclause (a) will be excluded in subsequent calculations of the amount of Restricted Payments and the proceeds received from any such transaction will be excluded from clause (c)(ii) of the preceding paragraph; and (b) loans or advances to employees or directors of the Parent Guarantor or any Subsidiary of the Parent Guarantor, in each case as permitted by Section 402 of the Sarbanes-Oxley Act of 2002, the proceeds of which are used to purchase Capital Stock of the Parent Guarantor, or to refinance loans or advances made pursuant to this clause (5)(b), in an aggregate principal amount not in excess of $2.0 million at any one time outstanding; *provided*, *however*, that the amount of such loans and advances will be included in subsequent calculations of the amount of Restricted Payments;

(6) purchases, repurchases, redemptions or other acquisitions or retirements for value of Capital Stock deemed to occur upon the exercise of stock options, warrants, rights to acquire Capital Stock or other convertible securities if such Capital Stock represents a portion of the exercise or exchange price thereof, and any purchases, repurchases, redemptions or other acquisitions or retirements for value of Capital Stock made in lieu of withholding taxes in connection with any exercise or exchange of warrants, options or rights to acquire Capital Stock; *provided*, *however*, that such acquisitions or retirements will be excluded from subsequent calculations of the amount of Restricted Payments;

(7) the purchase, repurchase, redemption, defeasance or other acquisition or retirement for value of any Subordinated Obligation (i) at a purchase price not greater than 101% of the principal amount of such Subordinated Obligation in the event of a Change of Control in accordance with provisions similar to the covenant described under "—Change of Control" or (ii) at a purchase price not greater than 100% of the principal amount thereof in accordance with provisions similar to the covenant described under "—Limitation on Sales of Assets and Subsidiary Stock"; *provided* that, prior to or simultaneously with such purchase, repurchase, redemption, defeasance or other acquisition or retirement, the Issuer has made the Change of Control Offer or Asset Disposition Offer, as applicable, as provided in such covenant with respect to the Notes and has completed the repurchase or redemption of all Notes validly tendered for payment in connection with such Change of Control Offer or Asset Disposition Offer; *provided*, *however*, that such acquisitions or retirements will be included in subsequent calculations of the amount of Restricted Payments;

(8) payments or distributions to dissenting stockholders pursuant to applicable law or in connection with the settlement or other satisfaction of legal claims made pursuant to or in connection with a consolidation, merger or transfer of assets; *provided*, *however*, that any payment pursuant to this clause (8) will be included in the calculation of the amount of Restricted Payments;

(9) cash payments in lieu of the issuance of fractional shares; *provided*, *however*, that any payment pursuant to this clause (9) will be excluded in the calculation of the amount of Restricted Payments;

(10) the declaration and payment of scheduled or accrued dividends to holders of any class of or series of Disqualified Stock of the Parent Guarantor issued after the Issue Date in accordance with the covenant captioned "—Limitation on Indebtedness and Preferred Stock", to the extent such dividends are included in Consolidated Interest Expense; *provided*, *however*, that any payment pursuant to this clause (10) will be excluded in the calculation of the amount of Restricted Payments; and

(11) Restricted Payments in an amount not to exceed $25 million in the aggregate since the Issue Date; *provided*, *however*, that the amount of such Restricted Payments will be included in subsequent calculations of the amount of Restricted Payments.

The amount of all Restricted Payments (other than cash) shall be the Fair Market Value on the date of such Restricted Payment of the asset(s) or securities proposed to be paid, transferred or issued by the Parent Guarantor or such Restricted Subsidiary, as the case may be, pursuant to such Restricted Payment. The Fair Market Value of any cash Restricted Payment shall be its face amount and the Fair Market Value of any non-cash Restricted Payment shall be determined in accordance with the definition of that term. Not later than the date of making any Restricted Payment in excess of $15.0 million that will be included in subsequent calculations of the amount of Restricted Payments, the Parent Guarantor shall deliver to the Trustee an Officers' Certificate stating that such Restricted Payment is permitted and setting forth the basis upon which the calculations required by the this covenant were computed.

In the event that a Restricted Payment meets the criteria of more than one of the exceptions described in (1) through (11) above or is entitled to be made pursuant to the first paragraph above, the Parent Guarantor shall, in its sole discretion, classify such Restricted Payment.

Currently, all of the Parent Guarantor's Subsidiaries are Restricted Subsidiaries. The Parent Guarantor will not permit any Unrestricted Subsidiary to become a Restricted Subsidiary except pursuant to the last sentence of the definition of "Unrestricted Subsidiary." For purpose of designating any Restricted Subsidiary as an Unrestricted Subsidiary, all outstanding Investments by the Parent Guarantor and its Restricted Subsidiaries (except to the extent repaid) in the Subsidiary so designated will be deemed to be Restricted Payments in an amount determined as set forth in the last sentence of the definition of "Investment." Such designation will be permitted only if a Restricted Payment in such amount would be permitted at such time, whether pursuant to the first paragraph of this covenant or under clause (11) of the second paragraph of this covenant, or pursuant to the definition of "Permitted Investments," and if such Subsidiary otherwise meets the definition of an Unrestricted Subsidiary. Unrestricted Subsidiaries will not be subject to any of the restrictive covenants set forth in the Indenture.

Limitation on Liens

The Parent Guarantor will not, and will not permit either the Issuer or any of its other Restricted Subsidiaries to, directly or indirectly, create, Incur or suffer to exist any Lien (the "Initial Lien") other than Permitted Liens upon any of its property or assets (including Capital Stock of Restricted Subsidiaries), including any income or profits therefrom, whether owned on the date of the Indenture or acquired after that date, which Lien is securing any Indebtedness, unless contemporaneously with the Incurrence of such Lien effective provision is made to secure the Indebtedness due under the Parent Guarantee or, in respect of Liens on any Restricted Subsidiary's property or assets, the Notes (in the case of the Issuer) or any Subsidiary Guarantee of such other Restricted Subsidiary, equally and ratably with (or senior in priority to in the case of Liens with respect to Subordinated Obligations or

Guarantor Subordinated Obligations, as the case may be) the Indebtedness secured by such Lien for so long as such Indebtedness is so secured.

Any Lien created for the benefit of the holders of the Notes pursuant to the preceding paragraph shall provide by its terms that such Lien shall be automatically and unconditionally released and discharged upon the release and discharge of the Initial Lien.

Limitation on Restrictions on Distributions from Restricted Subsidiaries

The Parent Guarantor will not, and will not permit any Restricted Subsidiary (other than the Issuer or a Subsidiary Guarantor) to, create or otherwise cause or permit to exist or become effective any consensual encumbrance or consensual restriction on the ability of any such Restricted Subsidiary to:

(1) pay dividends or make any other distributions on its Capital Stock or pay any Indebtedness or other obligations owed to the Parent Guarantor or any Restricted Subsidiary (it being understood that the priority of any Preferred Stock in receiving dividends or liquidating distributions prior to dividends or liquidating distributions being paid on Common Stock shall not be deemed a restriction on the ability to make distributions on Capital Stock);

(2) make any loans or advances to the Parent Guarantor or any Restricted Subsidiary (it being understood that the subordination of loans or advances made to the Parent Guarantor or any Restricted Subsidiary to other Indebtedness Incurred by the Parent Guarantor or any Restricted Subsidiary shall not be deemed a restriction on the ability to make loans or advances); or

(3) sell, lease or transfer any of its property or assets to the Parent Guarantor or any Restricted Subsidiary.

The preceding provisions will not prohibit:

(i) any encumbrance or restriction pursuant to or by reason of an agreement in effect at or entered into on the Issue Date, including, without limitation, the Indenture as in effect on such date;

(ii) any encumbrance or restriction with respect to a Person pursuant to or by reason of an agreement relating to any Capital Stock or Indebtedness Incurred by a Person on or before the date on which such Person was acquired by the Parent Guarantor or another Restricted Subsidiary (other than Capital Stock or Indebtedness Incurred as consideration in, or to provide all or any portion of the funds utilized to consummate, the transaction or series of related transactions pursuant to which such Person was acquired by the Parent Guarantor or a Restricted Subsidiary or in contemplation of the transaction) and outstanding on such date; *provided* that any such encumbrance or restriction shall not extend to any assets or property of the Parent Guarantor or any other Restricted Subsidiary other than the assets and property so acquired;

(iii) encumbrances and restrictions contained in contracts entered into in the ordinary course of business, not relating to any Indebtedness, and that do not, individually or in the aggregate, detract from the value of, or from the ability of the Parent Guarantor and the Restricted Subsidiaries to realize the value of, property or assets of the Parent Guarantor or any Restricted Subsidiary in any manner material to the Parent Guarantor or any Restricted Subsidiary;

(iv) any encumbrance or restriction with respect to a Unrestricted Subsidiary pursuant to or by reason of an agreement that the Unrestricted Subsidiary is a party to entered into before the date on which such Unrestricted Subsidiary became a Restricted Subsidiary; provided that such agreement was not entered into in anticipation of the Unrestricted Subsidiary becoming a Restricted Subsidiary and any such encumbrance or restriction shall not extend to any assets or property of the Parent Guarantor or any other Restricted Subsidiary other than the assets and property so acquired;

(v) with respect to any Foreign Subsidiary, any encumbrance or restriction contained in the terms of any Indebtedness or any agreement pursuant to which such Indebtedness was Incurred if either (1) the encumbrance or restriction applies only in the event of a payment default or a default with respect to a financial covenant in such Indebtedness or agreement or (2) the Parent Guarantor determines that any such encumbrance or restriction will not materially affect the Parent Guarantor's ability to make principal or interest payments on the Notes, as determined in good faith by the Board of Directors of the Parent Guarantor, whose determination shall be conclusive;

(vi) any encumbrance or restriction with respect to a Restricted Subsidiary pursuant to an agreement effecting a refunding, replacement or refinancing of Indebtedness Incurred pursuant to an agreement referred to in clauses (i) through (v) or clause (xii) of this paragraph or this clause (vi) or contained in any amendment, restatement, modification, renewal, supplemental, refunding, replacement or refinancing of an agreement referred to in clauses (i) through (v) or clause (xii) of this paragraph or this clause (vi); *provided* that the encumbrances and restrictions with respect to such Restricted Subsidiary contained in any such agreement taken as a whole are no less favorable in any material respect to the holders of the Notes than the encumbrances and restrictions contained in the agreements governing the Indebtedness being refunded, replaced or refinanced;

(vii) in the case of clause (3) of the first paragraph of this covenant, any encumbrance or restriction:

(a) that restricts in a customary manner the subletting, assignment or transfer of any property or asset that is subject to a lease (including leases governing leasehold interests or farm-in agreements or farm-out agreements relating to leasehold interests in Oil and Gas Properties), license or similar contract, or the assignment or transfer of any such lease (including leases governing leasehold interests or farm-in agreements or farm-out agreements relating to leasehold interests in Oil and Gas Properties), license (including, without limitation, licenses of intellectual property) or other contract;

(b) contained in mortgages, pledges or other security agreements permitted under the Indenture securing Indebtedness of the Parent Guarantor or a Restricted Subsidiary to the extent such encumbrances or restrictions restrict the transfer of the property subject to such mortgages, pledges or other security agreements;

(c) contained in any agreement creating Hedging Obligations permitted from time to time under the Indenture;

(d) pursuant to customary provisions restricting dispositions of real property interests set forth in any reciprocal easement agreements of the Parent Guarantor or any Restricted Subsidiary;

(e) restrictions on cash or other deposits imposed by customers under contracts entered into in the ordinary course of business; or

(f) provisions with respect to the disposition or distribution of assets or property in operating agreements, joint venture agreements, development agreements, area of mutual interest agreements and other agreements that are customary in the Oil and Gas Business and entered into in the ordinary course of business;

(viii) any encumbrance or restriction contained in (a) purchase money obligations for property acquired in the ordinary course of business and (b) Capitalized Lease Obligations permitted under the Indenture, in each case, that impose encumbrances or restrictions of the nature described in clause (3) of the first paragraph of this covenant on the property so acquired;

(ix) any encumbrance or restriction with respect to a Restricted Subsidiary (or any of its property or assets) imposed pursuant to an agreement entered into for the direct or indirect sale or disposition of all or a portion of the Capital Stock or assets of such Restricted Subsidiary (or the property or assets that are subject to such restriction) pending the closing of such sale or disposition;

(x) any customary encumbrances or restrictions imposed pursuant to any agreement of the type described in the definition of "Permitted Business Investment";

(xi) encumbrances or restrictions arising or existing by reason of applicable law or any applicable rule, regulation or order;

(xii) encumbrances or restrictions contained in agreements governing Indebtedness of the Parent Guarantor or any of its Restricted Subsidiaries permitted to be Incurred pursuant to an agreement entered into subsequent to the Issue Date in accordance with the covenant described under the caption "—Limitation on Indebtedness and Preferred Stock"; *provided* that the provisions relating to such encumbrance or restriction contained in such Indebtedness are not materially less favorable to the Parent Guarantor taken as a whole, as determined by the Board of Directors of the Parent Guarantor in good faith, than the provisions contained in the Senior Secured Credit Agreement and in the Indenture as in effect on the Issue Date;

(xiii) the issuance of Preferred Stock by a Restricted Subsidiary or the payment of dividends thereon in accordance with the terms thereof; *provided* that issuance of such Preferred Stock is permitted pursuant to the covenant described under the caption "—Limitation on Indebtedness and Preferred Stock" and the terms of such Preferred Stock do not expressly restrict the ability of a Restricted Subsidiary to pay dividends or make any other distributions on its Capital Stock (other than requirements to pay dividends or liquidation preferences on such Preferred Stock prior to paying any dividends or making any other distributions on such other Capital Stock);

(xiv) supermajority voting requirements existing under corporate charters, bylaws, stockholders agreements and similar documents and agreements;

(xv) restrictions on cash or other deposits or net worth imposed by customers under contracts entered into in the ordinary course of business; and

(xvi) any encumbrance or restriction contained in the Senior Secured Credit Agreement as in effect as of the Issue Date, and in any amendments, modifications, restatements, renewals, increases, supplements, refundings, replacements or refinancings thereof; *provided* that such amendments, modifications, restatements, renewals, increases, supplements, refundings, replacements or refinancings are no more restrictive with respect to such dividend and other payment restrictions than those contained in the Senior Secured Credit Agreement as in effect on the Issue Date.

Limitation on Sales of Assets and Subsidiary Stock

The Parent Guarantor will not, and will not permit any of its Restricted Subsidiaries to, make any Asset Disposition unless:

(1) the Parent Guarantor or such Restricted Subsidiary, as the case may be, receives consideration at the time of such Asset Disposition at least equal to the Fair Market Value (such Fair

Market Value to be determined on the date of contractually agreeing to such Asset Disposition) of the shares or other assets subject to such Asset Disposition;

(2) at least 75% of the aggregate consideration received by the Parent Guarantor or such Restricted Subsidiary, as the case may be, from such Asset Disposition and all other Asset Dispositions since the Issue Date, on a cumulative basis, is in the form of cash or Cash Equivalents or Additional Assets, or any combination thereof; and

(3) except as provided in the next paragraph, an amount equal to 100% of the Net Available Cash from such Asset Disposition is applied, within 365 days from the later of the date of such Asset Disposition or the receipt of such Net Available Cash, by the Parent Guarantor or such Restricted Subsidiary, as the case may be:

(a) to prepay, repay, redeem or purchase Pari Passu Indebtedness of the Parent Guarantor, the Issuer (including the Notes) or a Subsidiary Guarantor or any Indebtedness (other than Disqualified Stock) of a Restricted Subsidiary that is not a Subsidiary Guarantor (in each case, excluding Indebtedness owed to the Parent Guarantor or an Affiliate of the Parent Guarantor); *provided*, *however,* that, in connection with any prepayment, repayment, redemption or purchase of Indebtedness pursuant to this clause (a), the Parent Guarantor or such Restricted Subsidiary will retire such Indebtedness and will cause the related commitment (if any) to be permanently reduced in an amount equal to the principal amount so prepaid, repaid, redeemed or purchased; or

(b) to invest in Additional Assets;

provided that pending the final application of any such Net Available Cash in accordance with clause (a) or clause (b) above, the Parent Guarantor and its Restricted Subsidiaries may temporarily reduce Indebtedness or otherwise invest such Net Available Cash in any manner not prohibited by the Indenture.

Any Net Available Cash from Asset Dispositions that is not applied or invested as provided in the preceding paragraph will be deemed to constitute "Excess Proceeds." Not later than the 366th day from the later of the date of such Asset Disposition or the receipt of such Net Available Cash, if the aggregate amount of Excess Proceeds exceeds $20.0 million, the Issuer will be required to make an offer ("*Asset Disposition Offer*") to all holders of Notes and, to the extent required by the terms of other Pari Passu Indebtedness, to all holders of other Pari Passu Indebtedness outstanding with similar provisions requiring the Issuer to make an offer to purchase such Pari Passu Indebtedness with the proceeds from any Asset Disposition ("*Pari Passu Notes*") to purchase the maximum principal amount of Notes and any such Pari Passu Notes to which the Asset Disposition Offer applies that may be purchased out of the Excess Proceeds, at an offer price in cash in an amount equal to 100% of the principal amount (or, in the event such Pari Passu Indebtedness was issued with significant original issue discount, 100% of the accreted value thereof) of the Notes and Pari Passu Notes plus accrued and unpaid interest, if any (or in respect of such Pari Passu Indebtedness, such lesser price, if any, as may be provided for by the terms of such Indebtedness), to the date of purchase (subject to the right of holders of record on the relevant record date to receive interest due on the relevant interest payment date), in accordance with the procedures set forth in the Indenture or the agreements governing the Pari Passu Notes, as applicable, in each case in minimum principal amount of $2,000 and integral multiples of $1,000 in excess of $2,000. If the aggregate principal amount of Notes surrendered by holders thereof and other Pari Passu Notes surrendered by holders or lenders, collectively, exceeds the amount of Excess Proceeds, the Trustee shall select the Notes to be purchased on a pro rata basis on the basis of the aggregate principal amount of tendered Notes and Pari Passu Notes. To the extent that the aggregate amount of Notes and Pari Passu Notes so validly tendered and not properly withdrawn pursuant to an Asset Disposition Offer is less than the Excess Proceeds, the Parent Guarantor and its Restricted Subsidiaries may use any remaining Excess Proceeds for general corporate purposes, subject to the other covenants contained in the Indenture. Upon completion of such Asset Disposition Offer, the amount of Excess Proceeds shall be reset at zero.

The Asset Disposition Offer will remain open for a period of 20 Business Days following its commencement, except to the extent that a longer period is required by applicable law (the "*Asset Disposition Offer Period*"). No later than five Business Days after the termination of the Asset Disposition Offer Period (the "*Asset Disposition Purchase Date*"), the Issuer will purchase the principal amount of Notes and Pari Passu Notes required to be purchased pursuant to this covenant (the "*Asset Disposition Offer Amount*") or, if less than the Asset Disposition Offer Amount has been so validly tendered and not properly withdrawn, all Notes and Pari Passu Notes validly tendered and not properly withdrawn in response to the Asset Disposition Offer.

If the Asset Disposition Purchase Date is on or after an interest record date and on or before the related interest payment date, any accrued and unpaid interest, if any, will be paid to the Person in whose name a Note is registered at the close of business on such record date, and no further interest will be payable to holders who tender Notes pursuant to the Asset Disposition Offer.

On or before the Asset Disposition Purchase Date, the Issuer will, to the extent lawful, accept for payment, on a pro rata basis to the extent necessary, the Asset Disposition Offer Amount of Notes and Pari Passu Notes or portions of Notes and Pari Passu Notes so validly tendered and not properly withdrawn pursuant to the Asset Disposition Offer, or if less than the Asset Disposition Offer Amount has been validly tendered and not properly withdrawn, all Notes and Pari Passu Notes so validly tendered and not properly withdrawn, in each case in minimum principal amount of $2,000 and integral multiples of $1,000 in excess of $2,000. The Issuer will deliver to the Trustee an Officers' Certificate stating that such Notes or portions thereof were accepted for payment by the Issuer in accordance with the terms of this covenant and, in addition, the Issuer will deliver all certificates and notes required, if any, by the agreements governing the Pari Passu Notes. The Issuer or the paying agent, as the case may be, will promptly (but in any case not later than five Business Days after the termination of the Asset Disposition Offer Period) mail or deliver to each tendering holder of Notes or holder or lender of Pari Passu Notes, as the case may be, an amount equal to the purchase price of the Notes or Pari Passu Notes so validly tendered and not properly withdrawn by such holder or lender, as the case may be, and accepted by the Issuer for purchase, and the Issuer will promptly issue a new Note, and the Trustee, upon delivery of an Officers' Certificate from the Issuer, will authenticate and mail or deliver such new Note to such holder, in a principal amount equal to any unpurchased portion of the Note surrendered; *provided* that each such new Note will be in a minimum principal amount of $2,000 or an integral multiple of $1,000 in excess of $2,000. In addition, the Issuer will take any and all other actions required by the agreements governing the Pari Passu Notes. Any Note not so accepted will be promptly mailed or delivered by the Issuer to the holder thereof. The Issuer will publicly announce the results of the Asset Disposition Offer on the Asset Disposition Purchase Date.

The Issuer will comply, to the extent applicable, with the requirements of Rule 14e-1 of the Exchange Act and any other securities laws or regulations in connection with the repurchase of Notes pursuant to an Asset Disposition Offer. To the extent that the provisions of any securities laws or regulations conflict with provisions of this covenant, the Issuer will comply with the applicable securities laws and regulations and will not be deemed to have breached its obligations under the Indenture by virtue of its compliance with such securities laws or regulations.

For the purposes of clause (2) of the first paragraph of this covenant, the following will be deemed to be cash:

(1) the assumption by the transferee of Indebtedness (other than Guarantor Subordinated Obligations or Disqualified Stock) of the Parent Guarantor or Indebtedness of a Restricted Subsidiary (other than Subordinated Obligations or Disqualified Stock of the Issuer and Guarantor Subordinated Obligations or Disqualified Stock of any Restricted Subsidiary that is

a Subsidiary Guarantor) and the release of the Parent Guarantor or such Restricted Subsidiary from all liability on such Indebtedness in connection with such Asset Disposition (in which case the Parent Guarantor will, without further action, be deemed to have applied such deemed cash to Indebtedness in accordance with clause (3)(a) of the first paragraph of this covenant; and

(2) securities, notes or other obligations received by the Parent Guarantor or any Restricted Subsidiary from the transferee that are converted by the Parent Guarantor or such Restricted Subsidiary into cash within 180 days after receipt thereof.

Notwithstanding the foregoing, the 75% limitation referred to in clause (2) of the first paragraph of this covenant shall be deemed satisfied with respect to any Asset Disposition in which the cash or Cash Equivalents portion of the consideration received therefrom, determined in accordance with the foregoing provision on an after-tax basis, is equal to or greater than what the after-tax proceeds would have been had such Asset Disposition complied with the aforementioned 75% limitation.

The requirement of clause (3)(b) of the first paragraph of this covenant above shall be deemed to be satisfied if an agreement (including a lease, whether a capital lease or an operating lease) committing to make the acquisitions or expenditures referred to therein is entered into by the Parent Guarantor or its Restricted Subsidiary within the specified time period and such Net Available Cash is subsequently applied in accordance with such agreement within six months following such agreement.

The Parent Guarantor will not, and will not permit any Restricted Subsidiary to, engage in any Asset Swaps, unless:

(1) at the time of entering into such Asset Swap and immediately after giving effect to such Asset Swap, no Default or Event of Default shall have occurred and be continuing or would occur as a consequence thereof; and

(2) in the event such Asset Swap involves the transfer by the Parent Guarantor or any Restricted Subsidiary of assets having an aggregate Fair Market Value in excess of $20.0 million, the terms of such Asset Swap have been approved by a majority of the members of the Board of Directors of the Parent Guarantor.

Limitation on Affiliate Transactions

The Parent Guarantor will not, and will not permit any of its Restricted Subsidiaries to, directly or indirectly, enter into, make, amend or conduct any transaction (including making a payment to, the purchase, sale, lease or exchange of any property or the rendering of any service), contract, agreement or understanding with or for the benefit of any Affiliate of the Parent Guarantor (an "*Affiliate Transaction*") unless:

(1) the terms of such Affiliate Transaction are not materially less favorable to the Parent Guarantor or such Restricted Subsidiary, as the case may be, than those that could reasonably be expected to be obtained in a comparable transaction at the time of such transaction in arm's-length dealings with a Person who is not such an Affiliate;

(2) if such Affiliate Transaction involves an aggregate consideration in excess of $20.0 million, the terms of such transaction have been approved by a majority of the members of the Board of Directors of the Parent Guarantor having no personal stake in such transaction, if any (and such majority determines that such Affiliate Transaction satisfies the criteria in clause (1) above); and

(3) if such Affiliate Transaction involves an aggregate consideration in excess of $50.0 million, the Board of Directors of the Parent Guarantor has received a written opinion from an independent investment banking, accounting, engineering or appraisal firm of nationally

recognized standing that such Affiliate Transaction is fair, from a financial standpoint, to the Parent Guarantor or such Restricted Subsidiary or is not materially less favorable than those that could reasonably be expected to be obtained in a comparable transaction at such time on an arm's-length basis from a Person that is not an Affiliate.

The preceding paragraph will not apply to:

(1) any Restricted Payment permitted to be made pursuant to the covenant described under "—Limitation on Restricted Payments" or any Permitted Investment;

(2) any issuance of Capital Stock (other than Disqualified Stock), or other payments, awards or grants in cash, Capital Stock (other than Disqualified Stock) or otherwise pursuant to, or the funding of, employment or severance agreements and other compensation arrangements, options to purchase Capital Stock (other than Disqualified Stock) of the Parent Guarantor, restricted stock plans, long-term incentive plans, stock appreciation rights plans, participation plans or similar employee benefits plans and/or insurance and indemnification arrangements provided to or for the benefit of directors and employees approved by the Board of Directors of the Parent Guarantor;

(3) loans or advances to employees, officers or directors in the ordinary course of business of the Parent Guarantor or any of its Restricted Subsidiaries;

(4) advances to or reimbursements of employees for moving, entertainment and travel expenses, drawing accounts and similar expenditures in the ordinary course of business of the Parent Guarantor or any of its Restricted Subsidiaries;

(5) any transaction between the Parent Guarantor and a Restricted Subsidiary or between Restricted Subsidiaries, and guarantees issued by the Parent Guarantor or a Restricted Subsidiary for the benefit of the Parent Guarantor or a Restricted Subsidiary, as the case may be, in accordance with "—Limitation on Indebtedness and Preferred Stock";

(6) any transaction with a joint venture or similar entity which would constitute an Affiliate Transaction solely because the Parent Guarantor or a Restricted Subsidiary owns, directly or indirectly, an equity interest in or otherwise controls such joint venture or similar entity;

(7) the issuance or sale of any Capital Stock (other than Disqualified Stock) of the Parent Guarantor to, or the receipt by the Parent Guarantor of any capital contribution from its shareholders;

(8) indemnities of officers, directors and employees of the Parent Guarantor or any of its Restricted Subsidiaries permitted by bylaw or statutory provisions and any employment agreement or other employee compensation plan or arrangement entered into in the ordinary course of business by the Parent Guarantor or any of its Restricted Subsidiaries;

(9) the payment of reasonable compensation and fees paid to, and indemnity provided on behalf of, officers or directors of the Parent Guarantor or any Restricted Subsidiary;

(10) the performance of obligations of the Parent Guarantor or any of its Restricted Subsidiaries under the terms of any agreement to which the Parent Guarantor or any of its Restricted Subsidiaries is a party as of or on the Issue Date, as these agreements may be amended, modified, supplemented, extended or renewed from time to time; *provided*, *however*, that any future amendment, modification, supplement, extension or renewal entered into after the Issue Date will be permitted only to the extent that its terms are not materially more disadvantageous, taken as a whole, to the holders of the Notes than the terms of the agreements in effect on the Issue Date;

(11) transactions with customers, clients, suppliers, or purchasers or sellers of goods or services, in each case in the ordinary course of business and otherwise in compliance with the terms of the Indenture, *provided* that in the reasonable determination of the Board of Directors of the Parent Guarantor or the senior management of the Parent Guarantor, such transactions are on terms not materially less favorable to the Parent Guarantor or the relevant Restricted Subsidiary than those that could reasonably be expected to be obtained in a comparable transaction at such time on an arm's-length basis from a Person that is not an Affiliate of the Parent Guarantor;

(12) transactions with a Person (other than an Unrestricted Subsidiary) that is an Affiliate of the Parent Guarantor solely because the Parent Guarantor owns, directly or through a Restricted Subsidiary, an equity interest in such Person; and

(13) transactions between the Parent Guarantor or any Restricted Subsidiary and any Person, a director of which is also a director of the Parent Guarantor or any direct or indirect Parent Guarantor of the Parent Guarantor, and such director is the sole cause for such Person to be deemed an Affiliate of the Parent Guarantor or any Restricted Subsidiary; *provided*, *however*, that such director shall abstain from voting as a director of the Parent Guarantor or such direct or indirect Parent Guarantor, as the case may be, on any matter involving such other Person.

Provision of Financial Information

The Indenture provides that, whether or not the Parent Guarantor is subject to the reporting requirements of Section 13 or Section 15(d) of the Exchange Act, to the extent not prohibited by the Exchange Act, the Parent Guarantor will file with the SEC, and make available to the Trustee and the holders of the Notes without cost to any holder, the annual reports and the information, documents and other reports (or copies of such portions of any of the foregoing as the SEC may by rules and regulations prescribe) that are specified in Sections 13 and 15(d) of the Exchange Act and applicable to a U.S. corporation within the time periods specified therein with respect to a non-accelerated filer; *provided, however,* that no Annual Report on Form 10-K shall be due with respect to any fiscal year ending prior to December 31, 2010, no Quarterly Report on Form 10-Q shall be due with respect to any quarter ending prior to June 30, 2010 and no Current Report on Form 8-K shall be due with respect to any event occurring prior to the date of filing the Parent Guarantor's Quarterly Report on Form 10-Q for the quarter ending June 30, 2010. In the event that the Parent Guarantor is not permitted to file such reports, documents and information with the SEC pursuant to the Exchange Act, the Parent Guarantor will nevertheless make available such Exchange Act information to the Trustee and the holders of the Notes without cost to any holder as if the Parent Guarantor were subject to the reporting requirements of Section 13 or 15(d) of the Exchange Act within the time periods specified therein with respect to a non-accelerated filer.

In addition, the Parent Guarantor will make available to the Trustee and the holders of the Notes without cost to any holder (i) on or prior to December 18, 2009, unaudited combined financial statements of the Subsidiary Guarantors with respect to the nine months ended September 30, 2009, (ii) within 90 days after the end of the fiscal year ending December 31, 2009, audited consolidated financial statements of the Parent Guarantor and its Subsidiaries and (iii) within 45 days after the end of the fiscal quarter ending March 31, 2010, quarterly unaudited consolidated financial statements of the Parent Guarantor and its Subsidiaries. Such unaudited combined financial statements of the Subsidiary Guarantors will consist of a combined balance sheet of the Subsidiary Guarantors as of September 30, 2009 and combined statements of income and cash flows of the Subsidiary Guarantors for the nine months ended September 30, 2009, all in reasonable detail and duly certified (subject to normal year-end audit adjustments) by a principal financial or accounting officer of the Parent Guarantor as having been prepared in accordance with GAAP. Such audited consolidated financial statements of the Parent Guarantor and its Subsidiaries will consist of a consolidated balance sheet of the Parent Guarantor and its Subsidiaries as of December 31, 2009 and consolidated statements of income and cash flows of the Parent Guarantor and its Subsidiaries for the fiscal year then ended, accompanied by an opinion of KPMG LLP (or other independent public accountants of nationally recognized standing). Such quarterly unaudited consolidated financial statements of the Parent Guarantor and its Subsidiaries will consist of a consolidated balance sheet of the Parent Guarantor and its Subsidiaries as of March 31, 2010, and consolidated statements of income and cash flows of the Parent Guarantor and its Subsidiaries for the three months ending March 31, 2010, all in reasonable detail and duly certified (subject to normal year-end audit adjustments) by a principal financial or accounting officer of the Parent Guarantor as having been prepared in accordance with GAAP.

This covenant will not impose any duty on the Parent Guarantor under the Sarbanes-Oxley Act of 2002 and the related SEC rules that would not otherwise be applicable.

If the Parent Guarantor has designated any of its Subsidiaries as Unrestricted Subsidiaries, then the financial information required will include a reasonably detailed presentation, either on the face of the financial statements or in the footnotes thereto, and in any accompanying Management's Discussion and Analysis of Financial Condition and Results of Operations, of the financial condition and results of operations of the Parent Guarantor and its Restricted Subsidiaries separate from the financial condition and results of operations of the Unrestricted Subsidiaries of the Parent Guarantor.

The availability of the foregoing materials on the SEC's website or on the Parent Guarantor's website shall be deemed to satisfy the foregoing delivery obligations.

For so long as any Notes remain outstanding and constitute "restricted securities" under Rule 144, the Guarantors will furnish to the holders of the Notes, and to securities analysts and prospective investors, upon their request, the information required to be delivered pursuant to Rule 144A(d)(4) under the Securities Act.

Merger and Consolidation

Neither the Parent Guarantor nor the Issuer will consolidate with or merge with or into or wind up into (whether or not it is the surviving Person), or convey, transfer or lease all or substantially all its assets in one or more related transactions to, any Person, unless:

(1) the resulting, surviving or transferee Person (the "Successor Company") will be a corporation, partnership, trust or limited liability company organized and existing under the laws of the United States of America, any State of the United States or the District of Columbia and the Successor Company (if not the Parent Guarantor or the Issuer, as the case may be) will expressly assume, by supplemental indenture, executed and delivered to the Trustee, in form reasonably satisfactory to the Trustee, all the obligations of the Parent Guarantor or the Issuer, as the case may be, under the Indenture, the Notes or the Parent Guarantee as applicable;

(2) immediately after giving effect to such transaction (and treating any Indebtedness that becomes an obligation of the Successor Company or any Subsidiary of the Successor Company as a result of such transaction as having been Incurred by the Successor Company or such Subsidiary at the time of such transaction), no Default or Event of Default shall have occurred and be continuing;

(3) either (A) immediately after giving effect to such transaction, the Successor Company would be able to Incur at least an additional $1.00 of Indebtedness pursuant to the first paragraph of the covenant described under "—Limitation on Indebtedness and Preferred Stock" or (B) immediately after giving effect to such transaction on a pro forma basis and any related financing transactions as if the same had occurred at the beginning of the applicable four

quarter period, the Consolidated Coverage Ratio of the Parent Guarantor is equal to or greater than the Consolidated Coverage Ratio of the Parent Guarantor immediately before such transaction;

(4) if the Issuer is not the Successor Company in any of the transactions referred to above that involve the Issuer, each Guarantor (unless it is the other party to the transactions, in which case clause (1) shall apply) shall have by supplemental indenture confirmed that its Guarantee shall apply to the Successor Company's obligations in respect of the Indenture and the Notes and that its Guarantee shall continue to be in effect; and

(5) the Parent Guarantor or the Issuer, as the case may be, shall have delivered to the Trustee an Officers' Certificate and an Opinion of Counsel, each stating that such consolidation, merger, conveyance, transfer or lease and such supplemental indenture (if any) comply with the Indenture.

For purposes of this covenant, the sale, lease, conveyance, assignment, transfer or other disposition of all or substantially all of the properties and assets of one or more Subsidiaries of the Parent Guarantor, which properties and assets, if held by the Parent Guarantor instead of such Subsidiaries, would constitute all or substantially all of the properties and assets of the Parent Guarantor on a consolidated basis, shall be deemed to be the transfer of all or substantially all of the assets of the Parent Guarantor.

The Successor Company will succeed to, and be substituted for, and may exercise every right and power of, the Parent Guarantor or the Issuer, as the case may be, under the Indenture; and its predecessor, except in the case of a lease of all or substantially all its assets, will be released from all obligations under the Indenture, the Notes or the Parent Guarantee as applicable.

Although there is a limited body of case law interpreting the phrase "substantially all," there is no precise established definition of the phrase under applicable law. Accordingly, in certain circumstances there may be a degree of uncertainty as to whether a particular transaction would involve "all or substantially all" of the assets of a Person.

Notwithstanding the preceding clause (3), (x) any Restricted Subsidiary may consolidate with, merge into or transfer all or part of its assets to the Parent Guarantor and the Parent Guarantor may consolidate with, merge into or transfer all or part of its assets to a Subsidiary Guarantor and (y) the Parent Guarantor may merge with an Affiliate incorporated solely for the purpose of reorganizing the Parent Guarantor in another jurisdiction; and *provided further* that, in the case of a Restricted Subsidiary that consolidates with, merges into or transfers all or part of its properties and assets to the Parent Guarantor, the Issuer will not be required to comply with the preceding clause (5).

In addition, the Parent Guarantor will not permit any Subsidiary Guarantor to consolidate with or merge with or into, and will not permit the conveyance, transfer or lease of all or substantially all of the assets of any Subsidiary Guarantor to, any Person (other than the Parent Guarantor or another Subsidiary Guarantor) unless:

(1) (a) the resulting, surviving or transferee Person will be a corporation, partnership, trust or limited liability company organized and existing under the laws of the United States of America, any State of the United States or the District of Columbia and such Person (if not such Subsidiary Guarantor) will expressly assume, by supplemental indenture, executed and delivered to the Trustee, all the obligations of such Subsidiary Guarantor under its Subsidiary Guarantee; and (b) immediately after giving effect to such transaction (and treating any Indebtedness that becomes an obligation of the resulting, surviving or transferee Person or any Restricted Subsidiary as a result of such transaction as having been Incurred by such Person or such Restricted Subsidiary at the time of such transaction), no Default shall have occurred and be continuing; or

(2) the transaction is made in compliance with this covenant and the conditions described in the penultimate paragraph of "—Guarantees;" and

(3) the Parent Guarantor will have delivered to the Trustee an Officers' Certificate and an Opinion of Counsel, each stating that such consolidation, merger, conveyance, transfer or lease and such supplemental indenture (if any) comply with the Indenture.

Future Subsidiary Guarantors

The Parent Guarantor will cause (a) each Wholly-Owned Subsidiary of the Parent Guarantor (other than a Foreign Subsidiary) formed or acquired after the Issue Date and (b) any other Domestic Subsidiary (except the Issuer) that is not already a Subsidiary Guarantor that guarantees any Indebtedness of the Parent Guarantor, the Issuer or a Subsidiary Guarantor, in each case to execute and deliver to the Trustee within 30 days a supplemental indenture (in the form specified in the Indenture) pursuant to which such Subsidiary will unconditionally guarantee, on a joint and several basis, the full and prompt payment of the principal of, premium, if any, and interest on the Notes on a senior basis; *provided* that any Restricted Subsidiary that constitutes an Immaterial Subsidiary need not become a Subsidiary Guarantor until such time as it ceases to be an Immaterial Subsidiary.

Payments for Consent

Neither the Parent Guarantor nor any of its Restricted Subsidiaries will, directly or indirectly, pay or cause to be paid any consideration, whether by way of interest, fees or otherwise, to any holder of any Notes for or as an inducement to any consent, waiver or amendment of any of the terms or provisions of the Indenture or the Notes unless such consideration is offered to be paid or is paid to all holders of the Notes that consent, waive or agree to amend in the time frame set forth in the solicitation documents relating to such consent, waiver or amendment.

Business Activities

The Issuer may not engage in any business not related directly or indirectly to obtaining money or arranging financing for the Parent Guarantor or its Restricted Subsidiaries, the Issuer may not have any Subsidiary, and no Person other than the Parent Guarantor or any of its other Restricted Subsidiaries may own any Capital Stock of the Issuer.

Covenant Termination

From and after the occurrence of an Investment Grade Rating Event, the Parent Guarantor and its Restricted Subsidiaries will no longer be subject to the provisions of the Indenture described above under the following headings:

- "—Limitation on Indebtedness and Preferred Stock,"
- "—Limitation on Restricted Payments,"
- "—Limitation on Restrictions on Distributions from Restricted Subsidiaries,"
- "—Limitation on Sales of Assets and Subsidiary Stock,"
- "—Limitation on Affiliate Transactions" and
- Clause (3) of "—Merger and Consolidation"

(collectively, the "Eliminated Covenants"). As a result, after the date on which the Parent Guarantor and its Restricted Subsidiaries are no longer subject to the Eliminated Covenants, the Notes will be entitled to substantially reduced covenant protection. After the foregoing covenants have been terminated, the Parent Guarantor may not designate any of its Subsidiaries as Unrestricted Subsidiaries pursuant to the second sentence of the definition of "Unrestricted Subsidiary."

Events of Default

Each of the following is an Event of Default with respect to the Notes:

(1) default in any payment of interest on any Note when due, continued for 30 days;

(2) default in the payment of principal of or premium, if any, on any Note when due at its Stated Maturity, upon optional redemption, upon required repurchase, upon declaration of acceleration or otherwise;

(3) failure by the Issuer or any Guarantor to comply with its obligations under "—Certain Covenants—Merger and Consolidation";

(4) failure by the Parent Guarantor or the Issuer to comply for 30 days (or 180 days in the case of a Reporting Failure) after notice as provided below with any of its obligations under the covenant described under "—Change of Control" above or under the covenants described under "—Certain Covenants" above (in each case, other than a failure to purchase Notes which will constitute an Event of Default under clause (2) above and other than a failure to comply with "—Certain Covenants—Merger and Consolidation" which is covered by clause (3));

(5) failure by the Parent Guarantor or the Issuer to comply for 60 days after notice as provided below with its other agreements contained in the Indenture;

(6) default under any mortgage, indenture or instrument under which there may be issued or by which there may be secured or evidenced any Indebtedness for money borrowed by the Parent Guarantor or any of its Restricted Subsidiaries (or the payment of which is guaranteed by the Parent Guarantor or any of its Restricted Subsidiaries), other than Indebtedness owed to the Parent Guarantor or a Restricted Subsidiary, whether such Indebtedness or guarantee now exists, or is created after the date of the Indenture, which default:

(a) is caused by a failure to pay principal of, or interest or premium, if any, on such Indebtedness prior to the expiration of the grace period provided in such Indebtedness (and any extensions of any grace period) ("payment default"); or

(b) results in the acceleration of such Indebtedness prior to its Stated Maturity (the "cross acceleration provision");

and, in each case, the principal amount of any such Indebtedness, together with the principal amount of any other such Indebtedness under which there has been a payment default or the maturity of which has been so accelerated, aggregates $10.0 million or more;

(7) certain events of bankruptcy, insolvency or reorganization of the Parent Guarantor, the Issuer or a Significant Subsidiary or group of Restricted Subsidiaries that, taken together (as of the latest audited consolidated financial statements for the Parent Guarantor and its Restricted Subsidiaries), would constitute a Significant Subsidiary (the "bankruptcy provisions");

(8) failure by the Parent Guarantor, the Issuer or any Significant Subsidiary or group of Restricted Subsidiaries that, taken together (as of the latest audited consolidated financial statements for the Parent Guarantor and its Restricted Subsidiaries), would constitute a Significant Subsidiary to pay final judgments aggregating in excess of $10.0 million (to the extent not covered by insurance by a reputable and creditworthy insurer as to which the insurer has not disclaimed coverage), which judgments are not paid or discharged, and there shall be any period of 60 consecutive days following entry of such final judgment or decree

during which a stay of enforcement of such final judgment or decree, by reason of pending appeal or otherwise, shall not be in effect (the "judgment default provision"); or

(9) the Parent Guarantee or any Subsidiary Guarantee of a Significant Subsidiary or group of Restricted Subsidiaries that, taken together (as of the latest audited consolidated financial statements for the Parent Guarantor and its Restricted Subsidiaries) would constitute a Significant Subsidiary, ceases to be in full force and effect (except as contemplated by the terms of the Indenture) or is declared null and void in a judicial proceeding or the Parent Guarantor or any Subsidiary Guarantor that is a Significant Subsidiary or group of Subsidiary Guarantors that, taken together (as of the latest audited consolidated financial statements of the Parent Guarantor and its Restricted Subsidiaries) would constitute a Significant Subsidiary, denies or disaffirms its obligations under the Indenture or its Guarantee.

However, a default under clauses (4) and (5) of this paragraph will not constitute an Event of Default until the Trustee or the holders of at least 25% in principal amount of the outstanding Notes notify the Parent Guarantor and the Issuer in writing and, in the case of a notice given by the holders, the Trustee of the default and the Parent Guarantor or the Issuer does not cure such default within the time specified in clauses (4) and (5) of this paragraph after receipt of such notice.

If an Event of Default (other than an Event of Default described in clause (7) above) occurs and is continuing, the Trustee by notice to the Parent Guarantor and the Issuer, or the holders of at least 25% in principal amount of the outstanding Notes by notice to the Parent Guarantor and the Issuer and the Trustee, may, and the Trustee at the request of such holders shall, declare the principal of, premium, if any, accrued and unpaid interest, if any, on all the Notes to be due and payable. If an Event of Default described in clause (7) above occurs and is continuing, the principal of, premium, if any, accrued and unpaid interest, if any, on all the Notes will become and be immediately due and payable without any declaration or other act on the part of the Trustee or any holders. The holders of a majority in principal amount of the outstanding Notes may waive all past defaults (except with respect to nonpayment of principal, premium or interest) and rescind any such acceleration with respect to the Notes and its consequences if (1) rescission would not conflict with any judgment or decree of a court of competent jurisdiction and (2) all existing Events of Default, other than the nonpayment of the principal of, premium, if any, and interest on the Notes that have become due solely by such declaration of acceleration, have been cured or waived.

Notwithstanding the foregoing, if an Event of Default specified in clause (6) above shall have occurred and be continuing, such Event of Default and any consequential acceleration (to the extent not in violation of any applicable law or in conflict with any judgment or decree of a court of competent jurisdiction) shall be automatically rescinded if (i) the Indebtedness that is the subject of such Event of Default has been repaid or (ii) if the default relating to such Indebtedness is waived by the holders of such Indebtedness or cured and if such Indebtedness has been accelerated, then the holders thereof have rescinded their declaration of acceleration in respect of such Indebtedness, in each case within 20 days after the declaration of acceleration with respect thereto, and (iii) any other existing Events of Default, except nonpayment of principal, premium or interest on the Notes that became due solely because of the acceleration of the Notes, have been cured or waived.

Subject to the provisions of the Indenture relating to the duties of the Trustee, if an Event of Default occurs and is continuing, the Trustee will be under no obligation to exercise any of the rights or powers under the Indenture at the request or direction of any of the holders unless such holders have offered to the Trustee reasonable indemnity or security against any loss, liability or expense. Except to enforce the right to receive payment of principal, premium, if any, or interest when due, no holder may pursue any remedy with respect to the Indenture or the Notes unless:

(1) such holder has previously given the Trustee notice that an Event of Default is continuing;

(2) holders of at least 25% in principal amount of the outstanding Notes have requested the Trustee to pursue the remedy;

(3) such holders have offered the Trustee reasonable security or indemnity against any loss, liability or expense;

(4) the Trustee has not complied with such request within 60 days after the receipt of the request and the offer of security or indemnity; and

(5) the holders of a majority in principal amount of the outstanding Notes have not waived such Event of Default or otherwise given the Trustee a direction that, in the opinion of the Trustee, is inconsistent with such request within such 60-day period.

Subject to certain restrictions, the holders of a majority in principal amount of the outstanding Notes are given the right to direct the time, method and place of conducting any proceeding for any remedy available to the Trustee or of exercising any trust or power conferred on the Trustee. The Indenture provides that in the event an Event of Default has occurred and is continuing, the Trustee will be required in the exercise of its powers to use the degree of care that a prudent person would use in the conduct of his own affairs. The Trustee, however, may refuse to follow any direction that conflicts with law or the Indenture or that the Trustee determines is unduly prejudicial to the rights of any other holder or that would involve the Trustee in personal liability. Prior to taking any action under the Indenture, the Trustee will be entitled to indemnification satisfactory to it in its sole discretion against all losses and expenses caused by taking or not taking such action.

If a Default occurs and is continuing and is known to the Trustee, the Trustee must mail to each holder notice of the Default within 90 days after it occurs. Except in the case of a Default in the payment of principal of, premium, if any, or interest on any Note, the Trustee may withhold such notice if and so long as a committee of trust officers of the Trustee in good faith determines that withholding notice is in the interests of the holders. In addition, the Issuer is required to deliver to the Trustee, within 120 days after the end of each fiscal year, a certificate indicating whether the signers thereof know of any Default that occurred during the previous year. The Issuer also is required to deliver to the Trustee, within 30 days after the occurrence thereof, written notice of any Defaults, their status and what action the Issuer is taking or proposing to take in respect thereof.

Amendments and Waivers

Subject to certain exceptions, the Indenture and the Notes may be amended with the consent of the holders of a majority in principal amount of the Notes then outstanding (including without limitation, consents obtained in connection with a purchase of, or tender offer or exchange offer for, Notes) and, subject to certain exceptions, any past default or compliance with any provisions may be waived with the consent of the holders of a majority in principal amount of the Notes then outstanding (including, without limitation, consents obtained in connection with a purchase of, or tender offer or exchange offer for, Notes). However, without the consent of each holder of an outstanding Note affected, no amendment may, among other things:

(1) reduce the principal amount of Notes whose holders must consent to an amendment or waiver;

(2) reduce the stated rate of or extend the stated time for payment of interest on any Note;

(3) reduce the principal of or extend the Stated Maturity of any Note;

(4) reduce the premium payable upon the redemption of any Note as described above under "—Optional Redemption," change the time at which any Note may be redeemed as described above under "—Optional Redemption" or make any change relative to our obligation to make

an offer to repurchase the Notes as a result of a Change of Control as described above under "—Change of Control" after (but not before) the occurrence of such Change of Control;

(5) make any Note payable in money other than that stated in the Note;

(6) impair the right of any holder to receive payment of the principal of, premium, if any, and interest on such holder's Notes on or after the due dates therefor or to institute suit for the enforcement of any payment on or with respect to such holder's Notes;

(7) make any change in the amendment provisions which require each holder's consent or in the waiver provisions;

(8) modify the Guarantees in any manner adverse to the holders of the Notes; or

(9) make any change to or modify the ranking of the Notes that would adversely affect the holders.

Notwithstanding the foregoing, without the consent of any holder, the Issuer, the Guarantors and the Trustee may amend the Indenture and the Notes to:

(1) cure any ambiguity, omission, defect, mistake or inconsistency;

(2) provide for the assumption by a successor of the obligations of the Parent Guarantor, the Issuer or any Subsidiary Guarantor under the Indenture;

(3) provide for uncertificated Notes in addition to or in place of certificated Notes (*provided* that the uncertificated Notes are issued in registered form for purposes of Section 163(f) of the Code, or in a manner such that the uncertificated Notes are described in Section 163(f)(2)(B) of the Code);

(4) add Guarantors with respect to the Notes, including Subsidiary Guarantors, or release a Subsidiary Guarantor from its Subsidiary Guarantee and terminate such Subsidiary Guarantee; *provided* that the release and termination is in accordance with the applicable provisions of the Indenture;

(5) secure the Notes or Guarantees;

(6) add to the covenants of the Parent Guarantor, the Issuer or a Subsidiary Guarantor for the benefit of the holders or surrender any right or power conferred upon the Parent Guarantor, the Issuer or a Subsidiary Guarantor;

(7) make any change that does not adversely affect the rights of any holder; *provided, however,* that any change to conform the Indenture to this "Description of notes" will not be deemed to adversely affect such legal rights;

(8) comply with any requirement of the SEC in connection with the qualification of the Indenture under the Trust Indenture Act; or

(9) provide for the succession of a successor Trustee, *provided* that the successor Trustee is otherwise qualified and eligible to act as such under the Indenture.

The consent of the holders is not necessary under the Indenture to approve the particular form of any proposed amendment. It is sufficient if such consent approves the substance of the proposed amendment. A consent to any amendment or waiver under the Indenture by any holder of Notes given in connection with a tender of such holder's Notes will not be rendered invalid by such tender. After an amendment under the Indenture requiring the consent of the holders becomes effective, the Issuer is required to mail to the holders a notice briefly describing such amendment. However, the failure to give such notice to all the holders, or any defect in the notice will not impair or affect the validity of the amendment.

Defeasance

The Issuer at any time may terminate all its obligations under the Notes and the Indenture ("legal defeasance"), except for certain obligations, including those respecting the defeasance trust and obligations to register the transfer or exchange of the Notes, to replace mutilated, destroyed, lost or stolen Notes and to maintain a registrar and paying agent in respect of the Notes.

The Issuer at any time may terminate its obligations described under "—Change of Control" and the obligations of itself and the Parent Guarantor under the covenants described under "—Certain Covenants" (other than clauses (1), (2), (4) and (5) of "—Merger and Consolidation"), the operation of the cross default upon a payment default, cross acceleration provisions, the bankruptcy provisions with respect to Significant Subsidiaries, the judgment default provision, the Subsidiary Guarantee provision described under "—Events of Default" above and the limitations contained in clause (3) under "—Certain Covenants—Merger and Consolidation" above ("covenant defeasance").

If the Issuer exercises its legal defeasance or its covenant defeasance option, the Subsidiary Guarantees in effect at such time will terminate and, in the case of covenant defeasance, the Parent Guarantee will terminate.

The Issuer may exercise its legal defeasance option notwithstanding its prior exercise of its covenant defeasance option. If the Issuer exercises its legal defeasance option, payment of the Notes may not be accelerated because of an Event of Default with respect to the Notes. If the Issuer exercises its covenant defeasance option, payment of the Notes may not be accelerated because of an Event of Default specified in clause (4), (5), (6), (7) (with respect only to Significant Subsidiaries), (8) or (9) under "—Events of Default" above or because of the failure of the Parent Guarantor or the Issuer to comply with clause (3) under "—Certain Covenants—Merger and Consolidation" above.

In order to exercise either defeasance option, the Issuer or a Guarantor must, among other things, irrevocably deposit in trust (the "defeasance trust") with the Trustee money or U.S. Government Obligations for the payment of principal, premium, if any, and interest on the Notes to redemption or Stated Maturity, as the case may be, and must comply with certain other conditions, including delivery to the Trustee of an Opinion of Counsel (subject to customary exceptions and exclusions) to the effect that holders of the Notes will not recognize income, gain or loss for federal income tax purposes as a result of such deposit and defeasance and will be subject to federal income tax on the same amount and in the same manner and at the same times as would have been the case if such deposit and defeasance had not occurred. In the case of legal defeasance only, such Opinion of Counsel must be based on a ruling of the Internal Revenue Service or other change in applicable federal income tax law.

Satisfaction and Discharge

The Indenture will be discharged and will cease to be of further effect as to all Notes issued thereunder, when either:

(1) all Notes that have been authenticated (except lost, stolen or destroyed Notes that have been replaced or paid and Notes for whose payment money has theretofore been deposited in trust or segregated and held in trust by the Issuer and thereafter repaid to the Issuer or discharged from such trust) have been delivered to the Trustee for cancellation, or

(2) all Notes that have not been delivered to the Trustee for cancellation have become due and payable or will become due and payable within one year by reason of the giving of a notice of redemption or otherwise and the Issuer, the Parent Guarantor or any Subsidiary Guarantor has irrevocably deposited or caused to be irrevocably deposited with the Trustee as trust funds in trust solely for such purpose, cash in U.S. dollars, U.S. Government Obligations, or a combination thereof, in such amounts as will be sufficient without consideration of any reinvestment of interest, to pay and discharge the entire indebtedness on the Notes not

delivered to the Trustee for cancellation for principal and accrued interest to the date of Stated Maturity or redemption, and in each case certain other requirements set forth in the Indenture are satisfied.

No Personal Liability of Directors, Officers, Employees and Stockholders

No director, officer, employee, incorporator, stockholder, member, partner or trustee of the Parent Guarantor, the Issuer or any Subsidiary Guarantor, as such, shall have any liability for any obligations of the Parent Guarantor, the Issuer or any Subsidiary Guarantor under the Notes, the Indenture or the Guarantees or for any claim based on, in respect of, or by reason of, such obligations or their creation. Each holder by accepting a Note waives and releases all such liability. The waiver and release are part of the consideration for issuance of the Notes.

Concerning the Trustee

Wells Fargo Bank, National Association is the Trustee under the Indenture and has been appointed by the Issuer as registrar and paying agent with regard to the Notes. Such bank is a lender under the Senior Secured Credit Agreement.

The Indenture contains certain limitations on the rights of the Trustee, should it become a creditor of the Issuer or any Guarantor, to obtain payment of claims in certain cases, or to realize on certain property received in respect of any such claim as security or otherwise. The Trustee will be permitted to engage in other transactions; *provided, however*, that if it acquires any conflicting interest (as defined in the Trust Indenture Act) while any Default exists it must eliminate such conflict within 90 days, apply to the SEC for permission to continue as Trustee with such conflict or resign as Trustee.

Governing Law

The Indenture provides that it and the Notes will be governed by, and construed in accordance with, the laws of the State of New York.

Book-Entry; Delivery and Form

Global Notes

The new Notes, like the old Notes, will be issued in the form of one or more fully registered notes in global form, without interest coupons. Each Global Note will be deposited with the Trustee, as custodian for The Depository Trust Company ("DTC"), and registered in the name of Cede & Co., as nominee of DTC.

Ownership of beneficial interests in each global note will be limited to persons who have accounts with DTC ("DTC participants") or persons who hold interests through DTC participants. We expect that under procedures established by DTC:

- upon deposit of each global note with DTC's custodian, DTC will credit portions of the principal amount of the global notes to the accounts of the DTC participants designated by the exchange agent; and
- ownership of beneficial interests in each global note will be shown on, and transfer of ownership of those interests will be effected only through, records maintained by DTC (with respect to interests of DTC participants) and the records of DTC participants (with respect to other owners of beneficial interests in the global notes).

Beneficial interests in the global notes may not be exchanged for notes in physical, certificated form except in the limited circumstances described below.

Book-Entry Procedures for the Global Notes

All interests in the global notes will be subject to the operations and procedures of DTC, including its participants, Euroclear Bank S.A./N.V., as operator of the Euroclear System ("Euroclear"), and Clearstream Banking S.A. ("Clearstream"). We provide the following summaries of those operations and procedures solely for the convenience of investors. The operations and procedures of each settlement system are controlled by that settlement system and may be changed at any time.

- Neither we nor the Trustee is responsible for those operations or procedures.
- DTC has advised us that it is:
  - a limited purpose trust company organized under the laws of the State of New York;
  - a "banking organization" within the meaning of the New York State Banking Law;
  - a member of the Federal Reserve System;
  - a "clearing corporation" within the meaning of the Uniform Commercial Code; and
  - a "clearing agency" registered under Section 17A of the Exchange Act.

DTC was created to hold securities for its participants and to facilitate the clearance and settlement of securities transactions between its participants through electronic book-entry changes to the accounts of its participants. DTC's participants include securities brokers and dealers, including the initial purchasers, banks and trust companies, clearing corporations, and other organizations. Indirect access to DTC's system is also available to others such as banks, brokers, dealers, and trust companies. These indirect participants clear through or maintain a custodial relationship with a DTC participant, either directly or indirectly. Investors who are not DTC participants may beneficially own securities held by or on behalf of DTC only through DTC participants or indirect participants in DTC.

So long as DTC's nominee is the registered owner of a global note, that nominee will be considered the sole owner or holder of the notes represented by that global note for all purposes under the indenture. Except as provided below, owners of beneficial interests in a global note:

- will not be entitled to have notes represented by the global note registered in their names;
- will not receive or be entitled to receive physical, certificated notes; and
- will not be considered the owners or holders of the notes under the indenture for any purpose, including with respect to the giving of any direction, instruction, or approval to the Trustee.

As a result, each investor who owns a beneficial interest in a global note must rely on the procedures of DTC to exercise any rights of a holder of notes under the Indenture (and, if the investor is not a participant or an indirect participant in DTC, on the procedures of the DTC participant through which the investor owns its interest).

Payments of principal, premium (if any), and interest with respect to the new notes represented by a global note will be made by the Trustee to DTC's nominee, as the registered holder of the global note. Neither we nor the Trustee will have any responsibility or liability for the payment of amounts to owners of beneficial interests in a global note, for any aspect of the records relating to or payments made on account of those interests by DTC, or for maintaining, supervising, or reviewing any records of DTC relating to those interests.

Payments by participants and indirect participants in DTC to the owners of beneficial interests in a global note will be governed by standing instructions and customary industry practice and will be the responsibility of those participants or indirect participants and DTC.

Transfers between participants in DTC will be effected under DTC's procedures and will be settled in same-day funds. Transfers between participants in Euroclear or Clearstream will be effected in the ordinary way under the rules and operating procedures of those systems.

Cross market transfers between DTC participants, on the one hand, and Euroclear or Clearstream participants, on the other hand, will be effected within DTC through the DTC participants that are acting as depositaries for Euroclear and Clearstream. To deliver or receive an interest in a global note held in a Euroclear or Clearstream account, an investor must send transfer instructions to Euroclear or Clearstream, as the case may be, under the rules and procedures of that system and within the established deadlines of that system. If the transaction meets its settlement requirements, Euroclear or Clearstream, as the case may be, will send instructions to its DTC depositary to take action to effect final settlement by delivering or receiving interests in the relevant global notes in DTC, and making or receiving payment under normal procedures for same-day funds settlement applicable to DTC. Euroclear and Clearstream participants may not deliver instructions directly to the DTC depositaries that are acting for Euroclear or Clearstream.

Because of time zone differences, the securities account of a Euroclear or Clearstream participant that purchases an interest in a global note from a DTC participant will be credited on the business day for Euroclear or Clearstream immediately following the DTC settlement date. Cash received in Euroclear or Clearstream from the sale of an interest in a global note to a DTC participant will be received with value on the DTC settlement date but will be available in the relevant Euroclear or Clearstream cash account as of the business day for Euroclear or Clearstream following the DTC settlement date.

DTC, Euroclear, and Clearstream have agreed to the above procedures to facilitate transfers of interests in the global notes among participants in those settlement systems. However, the settlement systems are not obligated to perform these procedures and may discontinue or change these procedures at any time. Neither we nor the Trustee will have any responsibility for the performance by DTC, Euroclear, or Clearstream, or their participants or indirect participants, of their obligations under the rules and procedures governing their operations.

Certificated Notes

New Notes in physical, certificated form will be issued and delivered to each person that DTC identifies as a beneficial owner of the related notes only if:

- DTC notifies us at any time that it is unwilling or unable to continue as depositary for the global notes and a successor depositary is not appointed within 90 days;
- DTC ceases to be registered as a clearing agency under the Exchange Act and a successor depositary is not appointed within 90 days; or
- we, at our option, notify the Trustee that we elect to cause the issuance of certificated Notes.

Certain Definitions

"*Acquired Indebtedness*" means Indebtedness (i) of a Person or any of its Subsidiaries existing at the time such Person becomes or is merged with and into a Restricted Subsidiary or (ii) assumed in connection with the acquisition of assets from such Person, in each case whether or not Incurred by such Person in connection with, or in anticipation or contemplation of, such Person becoming a Restricted Subsidiary or such acquisition. Acquired Indebtedness shall be deemed to have been Incurred, with respect to clause (i) of the preceding sentence, on the date such Person becomes or is merged with and into a Restricted Subsidiary and, with respect to clause (ii) of the preceding sentence, on the date of consummation of such acquisition of assets.

"*Additional Assets*" means:

(1) any properties or assets to be used by the Parent Guarantor or a Restricted Subsidiary in the Oil and Gas Business;

(2) capital expenditures by the Parent Guarantor or a Restricted Subsidiary in the Oil and Gas Business;

(3) the Capital Stock of a Person that becomes a Restricted Subsidiary as a result of the acquisition of such Capital Stock by the Parent Guarantor or a Restricted Subsidiary; or

(4) Capital Stock constituting a minority interest in any Person that at such time is a Restricted Subsidiary;

provided, *however*, that, in the case of clauses (3) and (4), such Restricted Subsidiary is primarily engaged in the Oil and Gas Business.

"*Adjusted Consolidated Net Tangible Assets*" of the Parent Guarantor means (without duplication), as of the date of determination, the remainder of:

(a) the sum of:

(i) discounted future net revenues from proved oil and gas reserves of the Parent Guarantor and its Restricted Subsidiaries calculated in accordance with SEC guidelines before any state or federal income taxes, as estimated by the Parent Guarantor in a reserve report prepared as of the end of the Parent Guarantor's most recently completed fiscal year for which audited financial statements are available, as increased by, as of the date of determination, the estimated discounted future net revenues from

(A) estimated proved oil and gas reserves acquired since such year end, which reserves were not reflected in such year end reserve report, and

(B) estimated oil and gas reserves attributable to extensions, discoveries and other additions and upward revisions of estimates of proved oil and gas reserves since such year end due to exploration, development or exploitation, production or other activities, which would, in accordance with standard industry practice, cause such revisions (including the impact to proved reserves and future net revenues from estimated development costs incurred and the accretion of discount since such year end),

and decreased by, as of the date of determination, the estimated discounted future net revenues from

(C) estimated proved oil and gas reserves produced or disposed of since such year end, and

(D) estimated oil and gas reserves attributable to downward revisions of estimates of proved oil and gas reserves since such year end due to changes in geological conditions or other factors which would, in accordance with standard industry practice, cause such revisions, in each case calculated on a pre-tax basis and substantially in accordance with SEC guidelines,

in the case of clauses (A) through (D) utilizing prices and costs calculated in accordance with SEC guidelines as if the end of the most recent fiscal quarter preceding the date of determination for which such information is available to the Parent Guarantor were year end; *provided*, *however*, that in the case of each of the determinations made pursuant to clauses (A) through (D), such increases and decreases shall be as estimated by the Parent Guarantor's petroleum engineers;

(ii) the capitalized costs that are attributable to Oil and Gas Properties of the Parent Guarantor and its Restricted Subsidiaries to which no proved oil and gas reserves are attributable, based on the Parent Guarantor's books and records as of a date no earlier than the date of the Parent Guarantor's latest available annual or quarterly financial statements;

(iii) the Net Working Capital of the Parent Guarantor and its Restricted Subsidiaries on a date no earlier than the date of the Parent Guarantor's latest annual or quarterly financial statements; and

(iv) the greater of

(A) the net book value of other tangible assets of the Parent Guarantor and its Restricted Subsidiaries, as of a date no earlier than the date of the Parent Guarantor's latest annual or quarterly financial statements, and

(B) the appraised value, as estimated by independent appraisers, of other tangible assets of the Parent Guarantor and its Restricted Subsidiaries, as of a date no earlier than the date of the Parent Guarantor's latest audited financial statements; *provided*, that, if no such appraisal has been performed the Parent Guarantor shall not be required to obtain such an appraisal and only clause (iv)(A) of this definition shall apply;

minus

(b) the sum of:

(i) Minority Interests;

(ii) any net gas balancing liabilities of the Parent Guarantor and its Restricted Subsidiaries reflected in the Parent Guarantor's latest annual or quarterly balance sheet (to the extent not deducted in calculating Net Working Capital of the Parent Guarantor in accordance with clause (a)(iii) above of this definition);

(iii) to the extent included in (a)(i) above, the discounted future net revenues, calculated in accordance with SEC guidelines (but utilizing prices and costs calculated in accordance with SEC guidelines as if the end of the most recent fiscal quarter preceding the date of determination for which such information is available to the Parent Guarantor were year end), attributable to reserves which are required to be delivered to third parties to fully satisfy the obligations of the Parent Guarantor and its Restricted Subsidiaries with respect to Volumetric Production Payments (determined, if applicable, using the schedules specified with respect thereto); and

(iv) the discounted future net revenues, calculated in accordance with SEC guidelines, attributable to reserves subject to Dollar-Denominated Production Payments which, based on the estimates of production and price assumptions included in determining the discounted future net revenues specified in (a)(i) above, would be necessary to fully satisfy the payment obligations of the Parent Guarantor and its Subsidiaries with respect to Dollar-Denominated Production Payments (determined, if applicable, using the schedules specified with respect thereto).

If the Parent Guarantor changes its method of accounting from the successful efforts method of accounting to the full cost or a similar method, "Adjusted Consolidated Net Tangible Assets" will continue to be calculated as if the Parent Guarantor were still using the successful efforts method of accounting.

"*Affiliate*" of any specified Person means any other Person, directly or indirectly, controlling or controlled by or under direct or indirect common control with such specified Person. For the purposes of this definition, "control" when used with respect to any Person means the power to direct the management and policies of such Person, directly or indirectly, whether through the ownership of voting securities, by contract or otherwise; and the terms "controlling" and "controlled" have meanings correlative to the foregoing.

"*Asset Disposition*" means any direct or indirect sale, lease (including by means of Production Payments and Reserve Sales and a Sale/Leaseback Transaction but excluding an operating lease entered into in the ordinary course of the Oil and Gas Business), transfer, issuance or other disposition, or a series of related sales, leases, transfers, issuances or dispositions that are part of a common plan, of (A) shares of Capital Stock of a Restricted Subsidiary (other than Preferred Stock of Restricted Subsidiaries issued in compliance with the covenant described under the heading "—Certain Covenants—Limitation on Indebtedness and Preferred Stock," and directors' qualifying shares or shares required by applicable law to be held by a Person other than the Parent Guarantor or a Restricted Subsidiary), (B) all or substantially all the assets of any division or line of business of the Parent Guarantor or any Restricted Subsidiary (excluding any division or line of business the assets of which are owned by an Unrestricted Subsidiary) or (C) any other assets of the Parent Guarantor or any Restricted Subsidiary outside of the ordinary course of business of the Parent Guarantor or such Restricted Subsidiary (each referred to for the purposes of this definition as a "disposition"), in each case by the Parent Guarantor or any of its Restricted Subsidiaries, including any disposition by means of a merger, consolidation or similar transaction.

Notwithstanding the preceding, the following items shall not be deemed to be Asset Dispositions:

(1) a disposition by a Restricted Subsidiary to the Parent Guarantor or by the Parent Guarantor or a Restricted Subsidiary to a Restricted Subsidiary;

(2) a disposition of cash, Cash Equivalents or other financial assets in the ordinary course of business;

(3) a disposition of Hydrocarbons or mineral products inventory in the ordinary course of business;

(4) a disposition of damaged, unserviceable, obsolete or worn out equipment or equipment that is no longer necessary for the proper conduct of the business of the Parent Guarantor and its Restricted Subsidiaries and that is disposed of in each case in the ordinary course of business;

(5) transactions in accordance with the covenant described under "—Certain Covenants—Merger and Consolidation";

(6) an issuance of Capital Stock by a Restricted Subsidiary to the Parent Guarantor or to a Restricted Subsidiary;

(7) the making of a Permitted Investment or a Restricted Payment (or a disposition that would constitute a Restricted Payment but for the exclusions from the definition thereof) permitted by the covenant described under "—Certain Covenants—Limitation on Restricted Payments";

(8) an Asset Swap;

(9) dispositions of assets with a Fair Market Value of less than $10.0 million;

(10) Permitted Liens;

(11) dispositions of receivables in connection with the compromise, settlement or collection thereof in the ordinary course of business or in bankruptcy or similar proceedings and exclusive of factoring or similar arrangements;

(12) the licensing or sublicensing of intellectual property (including, without limitation, the licensing of seismic data) or other general intangibles and licenses, leases or subleases of other

property in the ordinary course of business which do not materially interfere with the business of the Parent Guarantor and its Restricted Subsidiaries;

(13) foreclosure on assets;

(14) any Production Payments and Reserve Sales; *provided* that any such Production Payments and Reserve Sales, other than incentive compensation programs on terms that are reasonably customary in the Oil and Gas Business for geologists, geophysicists and other providers of technical services to the Parent Guarantor or a Restricted Subsidiary, shall have been created, Incurred, issued, assumed or Guaranteed in connection with the financing of, and within 60 days after the acquisition of, the property that is subject thereto;

(15) a disposition of oil and natural gas properties in connection with tax credit transactions complying with Section 29 or any successor or analogous provisions of the Code;

(16) surrender or waiver of contract rights, oil and gas leases, or the settlement, release or surrender of contract, tort or other claims of any kind;

(17) the abandonment, farm out, lease or sublease of developed or undeveloped Oil and Gas Properties in the ordinary course of business; and

(18) a disposition (whether or not in the ordinary course of business) of any Oil and Gas Property or interest therein to which no proved reserves are attributable at the time of such disposition.

"*Asset Swap*" means any substantially contemporaneous (and in any event occurring within 180 days of each other) purchase and sale or exchange of any oil or natural gas properties or assets or interests therein between the Parent Guarantor or any of its Restricted Subsidiaries and another Person; *provided*, that any cash received must be applied in accordance with "—Certain Covenants—Limitation on Sales of Assets and Subsidiary Stock" as if the Asset Swap were an Asset Disposition.

"*Average Life*" means, as of the date of determination, with respect to any Indebtedness or Preferred Stock, the quotient obtained by dividing (1) the sum of the products of the numbers of years from the date of determination to the dates of each successive scheduled principal payment of such Indebtedness or redemption or similar payment with respect to such Preferred Stock multiplied by the amount of such payment by (2) the sum of all such payments.

"*Beneficial Owner*" has the meaning assigned to such term in Rule 13d-3 and Rule 13d-5 under the Exchange Act, except that in calculating the beneficial ownership of any particular "person" (as that term is used in Section 13(d)(3) of the Exchange Act), such "person" will be deemed to have beneficial ownership of all securities that such "person" has the right to acquire by conversion or exercise of other securities, whether such right is currently exercisable or is exercisable only after the passage of time. The terms "Beneficially Owns" and "Beneficially Owned" have a corresponding meaning.

"*Board of Directors*" means, as to any Person that is a corporation, the board of directors of such Person or any duly authorized committee thereof or as to any Person that is not a corporation, the board of managers or such other individual or group serving a similar function.

"*Business Day*" means each day that is not a Saturday, Sunday or other day on which commercial banking institutions in New York, New York are authorized or required by law to close.

"*Capital Stock*" of any Person means any and all shares, units, interests, rights to purchase, warrants, options, participations or other equivalents of or interests in (however designated) equity of such Person, including any Preferred Stock, but excluding any debt securities convertible into, or exchangeable for, such equity.

"*Capitalized Lease Obligations*" means an obligation that is required to be classified and accounted for as a capitalized lease for financial reporting purposes in accordance with GAAP, and the amount of

Indebtedness represented by such obligation will be the capitalized amount of such obligation at the time any determination thereof is to be made as determined in accordance with GAAP, and the Stated Maturity thereof will be the date of the last payment of rent or any other amount due under such lease prior to the first date such lease may be terminated without penalty.

"*Cash Equivalents*" means:

(1) securities issued or directly and fully guaranteed or insured by the United States Government or any agency or instrumentality of the United States (*provided* that the full faith and credit of the United States is pledged in support thereof), having maturities of not more than one year from the date of acquisition;

(2) marketable general obligations issued by any state of the United States of America or any political subdivision of any such state or any public instrumentality thereof maturing within one year from the date of acquisition and, at the time of acquisition, having a credit rating of "A" (or the equivalent thereof) or better from either S&P or Moody's;

(3) certificates of deposit, time deposits, eurodollar time deposits, overnight bank deposits or bankers' acceptances having maturities of not more than one year from the date of acquisition thereof issued by any commercial bank the short-term deposit of which is rated at the time of acquisition thereof at least "A-2" or the equivalent thereof by S&P, or "P-2" or the equivalent thereof by Moody's, and having combined capital and surplus in excess of $100.0 million;

(4) repurchase obligations with a term of not more than seven days for underlying securities of the types described in clauses (1), (2) and (3) entered into with any bank meeting the qualifications specified in clause (3) above;

(5) commercial paper rated at the time of acquisition thereof at least "A-2" or the equivalent thereof by S&P or "P-2" or the equivalent thereof by Moody's, or carrying an equivalent rating by a nationally recognized rating agency, if both of the two named Rating Agencies cease publishing ratings of investments, and in any case maturing within one year after the date of acquisition thereof; and

(6) interests in any investment company or money market fund which invests 95% or more of its assets in instruments of the type specified in clauses (1) through (5) above.

"*Cash Management Obligations*" means, with respect to the Issuer or any Guarantor, any obligations of such Person to U.S. Bank National Association or any other lender in respect of treasury management arrangements, depositary or other cash management services, including any treasury management line of credit.

"*Change of Control*" means:

(1) any "person" or "group" of related persons (as such terms are used in Sections 13(d) and 14(d) of the Exchange Act), other than a Permitted Holder, is or becomes the Beneficial Owner, directly or indirectly, of more than 50% of the total voting power of the Voting Stock of the Parent Guarantor (or its successor by merger, consolidation or purchase of all or substantially all of its assets) (for the purposes of this clause (1), such person or group shall be deemed to Beneficially Own any Voting Stock of the Parent Guarantor held by a parent entity, if such person or group Beneficially Owns, directly or indirectly, more than 50% of the total voting power of the Voting Stock of such parent entity);

(2) the first day on which a majority of the members of the Board of Directors of the Parent Guarantor are not Continuing Directors;

(3) the sale, lease, transfer, conveyance or other disposition (other than by way of merger or consolidation), in one or a series of related transactions, of all or substantially all of the assets

of the Parent Guarantor and its Restricted Subsidiaries taken as a whole to any "person" (as such term is used in Sections 13(d) and 14(d) of the Exchange Act); or

(4) the adoption by the members of the Parent Guarantor of a plan or proposal for the liquidation or dissolution of the Parent Guarantor.

Notwithstanding the preceding, a conversion of the Parent Guarantor or any of its Restricted Subsidiaries from a limited liability company, corporation, limited partnership or other form of entity to a limited liability company, corporation, limited partnership or other form of entity or an exchange of all of the outstanding Capital Stock in one form of entity for Capital Stock for another form of entity shall not constitute a Change of Control, so long as following such conversion or exchange the "persons" (as that term is used in Section 13(d)(3) of the Exchange Act) who Beneficially Owned the Capital Stock of the Parent Guarantor immediately prior to such transactions continue to Beneficially Own in the aggregate more than 50% of the Voting Stock of such entity, or continue to Beneficially Own sufficient Equity Interests in such entity to elect a majority of its directors, managers, trustees or other persons serving in a similar capacity for such entity, and, in either case no "person" Beneficially Owns more than 50% of the Voting Stock of such entity.

"*Code*" means the Internal Revenue Code of 1986, as amended.

"*Commodity Agreements*" means, in respect of any Person, any forward contract, commodity swap agreement, commodity option agreement or other similar agreement or arrangement in respect of Hydrocarbons used, produced, processed or sold by such Person that are customary in the Oil and Gas Business and designed to protect such Person against fluctuation in Hydrocarbon prices.

"*Common Stock*" means, with respect to any Person, any and all shares, interests or other participations in, and other equivalents (however designated and whether voting or nonvoting) of such Person's common stock whether or not outstanding on the Issue Date, and includes, without limitation, all series and classes of such common stock.

"*Consolidated Coverage Ratio*" means as of any date of determination, the ratio of (x) the aggregate amount of Consolidated EBITDAX of such Person for the period of the most recent four consecutive fiscal quarters ending prior to the date of such determination for which financial statements are in existence to (y) Consolidated Interest Expense for such four fiscal quarters, *provided*, *however*, that:

(1) if the Parent Guarantor or any Restricted Subsidiary:

(a) has Incurred any Indebtedness since the beginning of such period that remains outstanding on such date of determination or if the transaction giving rise to the need to calculate the Consolidated Coverage Ratio is an Incurrence of Indebtedness, Consolidated EBITDAX and Consolidated Interest Expense for such period will be calculated after giving effect on a pro forma basis to such Indebtedness and the use of proceeds thereof as if such Indebtedness had been Incurred on the first day of such period and such proceeds had been applied as of such date (except that in making such computation, the amount of Indebtedness under any revolving Credit Facility outstanding on the date of such calculation will be deemed to be (i) the average daily balance of such Indebtedness during such four fiscal quarters or such shorter period for which such facility was outstanding or (ii) if such revolving Credit Facility was created after the end of such four fiscal quarters, the average daily balance of such Indebtedness during the period from the date of creation of such revolving Credit Facility to the date of such calculation, in each case, *provided* that such average daily balance shall take into account any repayment of Indebtedness under such revolving Credit Facility as provided in clause (b)); or

(b) has repaid, repurchased, defeased or otherwise discharged any Indebtedness since the beginning of the period, including with the proceeds of such new Indebtedness, that is no longer outstanding on such date of determination or if the transaction giving rise to the need to calculate the Consolidated Coverage Ratio involves a discharge of Indebtedness (in each case other than Indebtedness Incurred under any revolving Credit Facility unless such Indebtedness has been permanently repaid and the related commitment terminated), Consolidated EBITDAX and Consolidated Interest Expense for such period will be calculated after giving effect on a pro forma basis to such discharge of such Indebtedness as if such discharge had occurred on the first day of such period;

(2) if, since the beginning of such period, the Parent Guarantor or any Restricted Subsidiary has made any Asset Disposition or if the transaction giving rise to the need to calculate the Consolidated Coverage Ratio is such an Asset Disposition, the Consolidated EBITDAX for such period will be reduced by an amount equal to the Consolidated EBITDAX (if positive) directly attributable to the assets which are the subject of such Asset Disposition for such period or increased by an amount equal to the Consolidated EBITDAX (if negative) directly attributable thereto for such period and Consolidated Interest Expense for such period shall be reduced by an amount equal to the Consolidated Interest Expense directly attributable to any Indebtedness of the Parent Guarantor or any Restricted Subsidiary repaid, repurchased, defeased or otherwise discharged with respect to the Parent Guarantor and its continuing Restricted Subsidiaries in connection with or with the proceeds from such Asset Disposition for such period (or, if the Capital Stock of any Restricted Subsidiary is sold, the Consolidated Interest Expense for such period directly attributable to the Indebtedness of such Restricted Subsidiary to the extent the Parent Guarantor and its continuing Restricted Subsidiaries are no longer liable for such Indebtedness after such sale);

(3) if, since the beginning of such period, the Parent Guarantor or any Restricted Subsidiary (by merger or otherwise) has made an Investment in any Restricted Subsidiary (or any Person which becomes a Restricted Subsidiary or is merged with or into the Parent Guarantor or a Restricted Subsidiary) or an acquisition (or will have received a contribution) of assets, including any acquisition or contribution of assets occurring in connection with a transaction causing a calculation to be made under the Indenture, which constitutes all or substantially all of a Parent Guarantor, division, operating unit, segment, business, group of related assets or line of business, Consolidated EBITDAX and Consolidated Interest Expense for such period will be calculated after giving pro forma effect thereto (including the Incurrence of any Indebtedness) as if such Investment or acquisition or contribution had occurred on the first day of such period; and

(4) if, since the beginning of such period, any Person (that subsequently became a Restricted Subsidiary or was merged with or into the Parent Guarantor or any Restricted Subsidiary since the beginning of such period) made any Asset Disposition or any Investment or acquisition of assets that would have required an adjustment pursuant to clause (2) or (3) above if made by the Parent Guarantor or a Restricted Subsidiary during such period, Consolidated EBITDAX and Consolidated Interest Expense for such period will be calculated after giving pro forma effect thereto as if such Asset Disposition or Investment or acquisition of assets had occurred on the first day of such period.

For purposes of this definition, whenever pro forma effect is to be given to any calculation under this definition, the pro forma calculations will be determined in good faith by a responsible financial or accounting officer of the Parent Guarantor; *provided* that such officer may in his or her discretion include any reasonably identifiable and factually supportable pro forma changes to Consolidated EBITDAX, including any pro forma expenses and cost reductions, that have occurred or in the judgment of such officer are reasonably expected to occur within 12 months of the date of the applicable transaction (regardless of whether such expense or cost reduction or any other operating improvements could then be reflected properly in pro forma financial statements prepared in accordance with Regulation S-X under the Securities Act or any other regulation or policy of the SEC). If any Indebtedness bears a floating rate of interest and is being given pro forma effect, the interest expense on such Indebtedness will be calculated as if the average rate in effect from the beginning of such period to the date of determination had been the applicable rate for the entire period (taking into account any Interest Rate Agreement applicable to such Indebtedness, but if the remaining term of such Interest Rate Agreement is less than 12 months, then such Interest Rate Agreement shall only be taken into account for that portion of the period equal to the remaining term thereof). If any Indebtedness that is being given pro forma effect bears an interest rate at the option of the Parent Guarantor, the interest rate shall be calculated by applying such optional rate chosen by the Parent Guarantor. Interest on Indebtedness that may optionally be determined at an interest rate based upon a factor of a prime or similar rate, a eurocurrency interbank offered rate, or other rate, shall be deemed to have been based upon the rate actually chosen, or, if none, then based upon such optional rate chosen as the Parent Guarantor may designate.

"*Consolidated EBITDAX*" for any period means, without duplication, the Consolidated Net Income for such period, plus the following, without duplication and to the extent deducted (and not added back) in calculating such Consolidated Net Income:

(1) Consolidated Interest Expense;

(2) Consolidated Income Tax Expense;

(3) consolidated depletion and depreciation expense of the Parent Guarantor and its Restricted Subsidiaries;

(4) consolidated amortization expense or impairment charges of the Parent Guarantor and its Restricted Subsidiaries recorded in connection with the application of Statement of Financial Accounting Standard No. 142, "Goodwill and Other Intangibles" and Statement of Financial Accounting Standard No. 144, "Accounting for the Impairment or Disposal of Long Lived Assets";

(5) other non-cash charges of the Parent Guarantor and its Restricted Subsidiaries (excluding any such non-cash charge to the extent it represents an accrual of or reserve for cash charges in any future period or amortization of a prepaid cash expense that was paid in a prior period not included in the calculation); and

(6) consolidated exploration and abandonment expense of the Parent Guarantor and its Restricted Subsidiaries,

if applicable for such period; and less, to the extent included in calculating such Consolidated Net Income and in excess of any costs or expenses attributable thereto that were deducted (and not added back) in calculating such Consolidated Net Income, the sum of (x) the amount of deferred revenues that are amortized during such period and are attributable to reserves that are subject to Volumetric Production Payments, (y) amounts recorded in accordance with GAAP as repayments of principal and interest pursuant to Dollar-Denominated Production Payments and (z) other non-cash gains (excluding any non-cash gain to the extent it represents the reversal of an accrual or reserve for a potential cash item that reduced Consolidated EBITDAX in any prior period).

Notwithstanding the preceding sentence, clauses (2) through (6) relating to amounts of a Restricted Subsidiary of the Parent Guarantor will be added to Consolidated Net Income to compute Consolidated EBITDAX of the Parent Guarantor only to the extent (and in the same proportion) that the net income (loss) of such Restricted Subsidiary was included in calculating the Consolidated Net Income of the Parent Guarantor and, to the extent the amounts set forth in clauses (2) through (6) are in excess of those necessary to offset a net loss of such Restricted Subsidiary or if such Restricted Subsidiary has net income for such period included in Consolidated Net Income, only if a corresponding amount would be permitted at the date of determination to be dividended to the Parent Guarantor by such Restricted Subsidiary (unless it is a Guarantor) without prior approval (that has not been obtained), pursuant to the terms of its charter and all agreements, instruments, judgments, decrees, orders, statutes, rules and governmental regulations applicable to that Restricted Subsidiary or the holders of its Capital Stock.

"*Consolidated Income Tax Expense*" means, with respect to any period, the provision for federal, state, local and foreign income taxes (including state franchise taxes) of the Parent Guarantor and its Restricted Subsidiaries for such period as determined in accordance with GAAP.

"*Consolidated Interest Expense*" means, for any period, the total consolidated interest expense (less interest income) of the Parent Guarantor and its Restricted Subsidiaries, whether paid or accrued, plus, to the extent not included in such interest expense and without duplication:

(1) interest expense attributable to Capitalized Lease Obligations and the interest component of any deferred payment obligations;

(2) amortization of debt discount and debt issuance cost (*provided* that any amortization of bond premium will be credited to reduce Consolidated Interest Expense unless, pursuant to GAAP, such amortization of bond premium has otherwise reduced Consolidated Interest Expense);

(3) non-cash interest expense;

(4) commissions, discounts and other fees and charges owed with respect to letters of credit and bankers' acceptance financing;

(5) the interest expense on Indebtedness of another Person that is Guaranteed by the Parent Guarantor or one of its Restricted Subsidiaries or secured by a Lien on assets of the Parent Guarantor or one of its Restricted Subsidiaries, to the extent such Guarantee becomes payable or such Lien becomes subject to foreclosure;

(6) cash costs associated with Interest Rate Agreements (including amortization of fees); *provided*, *however*, that if Interest Rate Agreements result in net cash benefits rather than costs, such benefits shall be credited to reduce Consolidated Interest Expense unless, pursuant to GAAP, such net benefits are otherwise reflected in Consolidated Net Income;

(7) the consolidated interest expense of the Parent Guarantor and its Restricted Subsidiaries that was capitalized during such period; and

(8) all dividends paid or payable in cash, Cash Equivalents or Indebtedness or accrued during such period on any series of Disqualified Stock of the Parent Guarantor or on Preferred Stock of its Restricted Subsidiaries payable to a party other than the Parent Guarantor or a Wholly-Owned Subsidiary,

minus, to the extent included above, any interest attributable to Dollar-Denominated Production Payments.

For the purpose of calculating the Consolidated Coverage Ratio in connection with the Incurrence of any Indebtedness described in the final paragraph of the definition of "Indebtedness," the calculation of Consolidated Interest Expense shall include all interest expense (including any amounts described in clauses (1) through (8) above) relating to any Indebtedness of the Parent Guarantor or any Restricted Subsidiary described in the final paragraph of the definition of "Indebtedness."

"*Consolidated Net Income*" means, for any period, the aggregate net income (loss) of the Parent Guarantor and its consolidated Subsidiaries determined in accordance with GAAP and before any reduction in respect of Preferred Stock dividends of such Person; *provided*, *however*, that there will not be included (to the extent otherwise included therein) in such Consolidated Net Income:

(1) any net income (loss) of any Person (other than the Parent Guarantor) if such Person is not a Restricted Subsidiary, except that:

(a) subject to the limitations contained in clauses (3) and (4) below, the Parent Guarantor's equity in the net income of any such Person for such period will be included in such Consolidated Net Income up to the aggregate amount of cash actually distributed by such Person during such period to the Parent Guarantor or a Restricted Subsidiary as a dividend or other distribution (subject, in the case of a dividend or other distribution to a Restricted Subsidiary, to the limitations contained in clause (2) below); and

(b) the Parent Guarantor's equity in a net loss of any such Person for such period will be included in determining such Consolidated Net Income to the extent such loss has been funded with cash from the Parent Guarantor or a Restricted Subsidiary during such period;

(2) any net income (but not loss) of any Restricted Subsidiary (other than a Guarantor) if such Subsidiary is subject to restrictions, directly or indirectly, on the payment of dividends or the making of distributions by such Restricted Subsidiary, directly or indirectly, to the Parent Guarantor, except that:

(a) subject to the limitations contained in clauses (3), (4) and (5) below, the Parent Guarantor's equity in the net income of any such Restricted Subsidiary for such period will be included in such Consolidated Net Income up to the aggregate amount of cash that could have been distributed by such Restricted Subsidiary during such period to the Parent Guarantor or another Restricted Subsidiary as a dividend or other distribution (subject, in the case of a dividend or other distribution paid to another Restricted Subsidiary, to the limitation contained in this clause); and

(b) the Parent Guarantor's equity in a net loss of any such Restricted Subsidiary for such period will be included in determining such Consolidated Net Income;

(3) any gain (loss) realized upon the sale or other disposition of any property, plant or equipment of the Parent Guarantor or its consolidated Subsidiaries (including pursuant to any Sale/Leaseback Transaction) which is not sold or otherwise disposed of in the ordinary course of business and any gain (loss) realized upon the sale or other disposition of any Capital Stock of any Person;

(4) any extraordinary or nonrecurring gains or losses, together with any related provision for taxes on such gains or losses and all related fees and expenses;

(5) the cumulative effect of a change in accounting principles;

(6) any asset impairment writedowns on Oil and Gas Properties under GAAP or SEC guidelines;

(7) any unrealized non-cash gains or losses or charges in respect of Hedging Obligations (including those resulting from the application of Statement of Financial Accounting Standard No. 133);

(8) income or loss attributable to discontinued operations (including, without limitation, operations disposed of during such period whether or not such operations were classified as discontinued);

(9) all deferred financing costs written off, and premiums paid, in connection with any early extinguishment of Indebtedness; and

(10) any non-cash compensation charge arising from any grant of stock, stock options or other equity based awards; *provided* that the proceeds resulting from any such grant will be excluded from clause (c) (ii) of the first paragraph of the covenant described under "—Limitation on Restricted Payments."

"*Continuing Directors*" means, as of any date of determination, any member of the Board of Directors of the Parent Guarantor who: (1) was a member of such Board of Directors on the date of the Indenture; or (2) was nominated for election or elected to such Board of Directors with the approval of a majority of the Continuing Directors who were members of such Board of Directors at the time of such nomination or election.

"*Credit Facility*" means, with respect to the Parent Guarantor or any Restricted Subsidiary, one or more debt facilities (including, without limitation, the Senior Secured Credit Agreement), indentures or commercial paper facilities providing for revolving credit loans, term loans, receivables financing (including through the sale of receivables to such lenders or to special purpose entities formed to borrow from such lenders against such receivables) or letters of credit, in each case, as amended, restated, modified, renewed, refunded, replaced or refinanced in whole or in part from time to time (and whether or not with the original administrative agent and lenders or another administrative agent or agents or other lenders and whether provided under the original Senior Secured Credit Agreement or any other credit or other agreement or indenture).

"*Currency Agreement*" means in respect of a Person any foreign exchange contract, currency swap agreement, futures contract, option contract or other similar agreement as to which such Person is a party or a beneficiary.

"*Default*" means any event which is, or after notice or passage of time or both would be, an Event of Default.

"*Disqualified Stock*" means, with respect to any Person, any Capital Stock of such Person which by its terms (or by the terms of any security into which it is convertible or for which it is exchangeable) at the option of the holder of the Capital Stock or upon the happening of any event:

(1) matures or is mandatorily redeemable (other than redeemable only for Capital Stock of such Person which is not itself Disqualified Stock) pursuant to a sinking fund obligation or otherwise;

(2) is convertible or exchangeable for Disqualified Stock or other Indebtedness (excluding Capital Stock which is convertible or exchangeable solely at the option of the Parent Guarantor or a Restricted Subsidiary); or

(3) is redeemable at the option of the holder of the Capital Stock in whole or in part,

in each case on or prior to the date that is 91 days after the earlier of the date (a) of the Stated Maturity of the Notes or (b) on which there are no Notes outstanding; *provided* that only the portion of Capital Stock which so matures or is mandatorily redeemable, is so convertible or exchangeable or is so redeemable at the option of the holder thereof prior to such date will be deemed to be Disqualified Stock; *provided further*, that any Capital Stock that would constitute Disqualified Stock solely because the holders thereof have the right to require the Parent Guarantor to repurchase such Capital Stock upon the occurrence of a change of control or asset sale (each defined in a substantially identical manner to the corresponding definitions in the Indenture) shall not constitute Disqualified Stock if the terms of such Capital Stock (and all such securities into which it is convertible or for which it is exchangeable) provide that (i) the Parent Guarantor may not repurchase or redeem any such Capital Stock (and all such securities into which it is convertible or for which it is ratable or exchangeable) pursuant to such provision prior to compliance by the Parent Guarantor with the provisions of the Indenture described under the captions "—Change of Control" and "—Certain Covenants—Limitation on Sales of Assets and Subsidiary Stock" and (ii) such repurchase or redemption will be permitted solely to the extent also permitted in accordance with the provisions of the Indenture described under the caption "—Certain Covenants—Limitation on Restricted Payments."

"*Dollar-Denominated Production Payments*" means production payment obligations recorded as liabilities in accordance with GAAP, together with all undertakings and obligations in connection therewith.

"*Domestic Subsidiary*" means any Restricted Subsidiary that is organized under the laws of the United States of America or any state thereof or the District of Columbia.

"*Equity Offering*" means a public or private offering for cash by the Parent Guarantor of Capital Stock (other than Disqualified Stock), other than public offerings registered on Form S-8.

"*Exchange Act*" means the Securities Exchange Act of 1934, as amended, and the rules and regulations of the SEC promulgated thereunder.

"*Exchange Notes*" means Notes issued in exchange for old Notes or Additional Notes pursuant to a Registration Rights Agreement.

"*Fair Market Value*" means, with respect to any asset or property, the sale value that would be obtained in an arm's-length free market transaction between an informed and willing seller under no compulsion to sell and an informed and willing buyer under no compulsion to buy. Fair Market Value of an asset or property in excess of $10.0 million shall be determined by the Board of Directors of the Parent Guarantor acting in good faith, whose determination shall be conclusive and evidenced by a resolution of such Board of Directors, and any lesser Fair Market Value may be determined by an officer of the Parent Guarantor acting in good faith.

"*Foreign Subsidiary*" means any Restricted Subsidiary that is not organized under the laws of the United States of America or any state thereof or the District of Columbia.

"*GAAP*" means generally accepted accounting principles in the United States of America as in effect from time to time. All ratios and computations based on GAAP contained in the Indenture will be computed in conformity with GAAP.

The term "*guarantee*" means any obligation, contingent or otherwise, of any Person directly or indirectly guaranteeing any Indebtedness of any other Person and any obligation, direct or indirect, contingent or otherwise, of such Person:

(1) to purchase or pay (or advance or supply funds for the purchase or payment of) such Indebtedness of such other Person (whether arising by virtue of partnership arrangements, or by agreement to keep-well, to purchase assets, goods, securities or services, to take-or-pay, or to maintain financial statement conditions or otherwise); or

(2) entered into for purposes of assuring in any other manner the obligee of such Indebtedness of the payment thereof or to protect such obligee against loss in respect thereof (in whole or in part);

provided, *however*, that the term "guarantee" will not include endorsements for collection or deposit in the ordinary course of business or any obligation to the extent it is payable only in Capital Stock of the guarantor that is not Disqualified Stock. The term "guarantee" used as a verb has a corresponding meaning.

"*Guarantees*" means the Parent Guarantee and the Subsidiary Guarantees collectively.

"*Guarantors*" means the Parent Guarantor and the Subsidiary Guarantors collectively.

"*Guarantor Subordinated Obligation*" means, with respect to a Guarantor, any Indebtedness of such Guarantor (whether outstanding on the Issue Date or thereafter Incurred) which is expressly subordinated in right of payment to the obligations of such Guarantor under its Guarantee pursuant to a written agreement.

"*Hedging Obligations*" of any Person means the obligations of such Person pursuant to any Interest Rate Agreement, Currency Agreement or Commodity Agreement.

"*holder*" means a Person in whose name a Note is registered on the registrar's books.

"*Hydrocarbons*" means oil, natural gas, casing head gas, drip gasoline, natural gasoline, condensate, distillate, liquid hydrocarbons, gaseous hydrocarbons and all constituents, elements or compounds thereof and products refined or processed therefrom.

"*Immaterial Subsidiary*" means, as of any date, any Restricted Subsidiary whose total assets, as of the end of the most recent month for which financial statements are available, are less than $1,000,000 and whose total revenues for the most recent 12-month period for which financial statements are available do not exceed $1,000,000; *provided* that a Restricted Subsidiary will not be considered to be an Immaterial Subsidiary if it, directly or indirectly, guarantees or otherwise provides direct credit support for any Indebtedness of the Parent Guarantor.

"*Incur*" means issue, create, assume, Guarantee, incur or otherwise become directly or indirectly liable for, contingently or otherwise; *provided*, *however*, that any Indebtedness or Capital Stock of a Person existing at the time such Person becomes a Restricted Subsidiary (whether by merger, consolidation, acquisition or otherwise) will be deemed to be Incurred by such Restricted Subsidiary at the time it becomes a Restricted Subsidiary; and the terms "Incurred" and "Incurrence" have meanings correlative to the foregoing.

"*Indebtedness*" means, with respect to any Person on any date of determination (without duplication, whether or not contingent):

(1) the principal of and premium (if any) in respect of indebtedness of such Person for borrowed money;

(2) the principal of and premium (if any) in respect of obligations of such Person evidenced by bonds, debentures, notes or other similar instruments;

(3) the principal component of all obligations of such Person in respect of letters of credit, bankers' acceptances or other similar instruments (including reimbursement obligations with respect thereto except to the extent such reimbursement obligation relates to a trade payable, to the extent such letters of credit are not drawn upon or, if and to the extent drawn upon, such obligation is satisfied within 30 days of payment on the letter of credit);

(4) the principal component of all obligations of such Person (other than obligations payable solely in Capital Stock that is not Disqualified Stock) to pay the deferred and unpaid purchase price of property (except as described in clause (8) of the penultimate paragraph of this definition of "Indebtedness"), which purchase price is due more than six months after the date of placing such property in service or taking delivery and title thereto to the extent such obligations would appear as a liabilities upon the consolidated balance sheet of such Person in accordance with GAAP;

(5) Capitalized Lease Obligations of such Person to the extent such Capitalized Lease Obligations would appear as liabilities on the consolidated balance sheet of such Person in accordance with GAAP;

(6) the principal component or liquidation preference of all obligations of such Person with respect to the redemption, repayment or other repurchase of any Disqualified Stock or, with

respect to any Subsidiary that is not a Subsidiary Guarantor, any Preferred Stock (but excluding, in each case, any accrued dividends);

(7) the principal component of all Indebtedness of other Persons secured by a Lien on any asset of such Person, whether or not such Indebtedness is assumed by such Person; *provided*, *however*, that the amount of such Indebtedness will be the lesser of (a) the Fair Market Value of such asset at such date of determination and (b) the amount of such Indebtedness of such other Persons;

(8) the principal component of Indebtedness of other Persons to the extent Guaranteed by such Person; and

(9) to the extent not otherwise included in this definition, net obligations of such Person under Commodity Agreements, Currency Agreements and Interest Rate Agreements (the amount of any such obligations to be equal at any time to the termination value of such agreement or arrangement giving rise to such obligation that would be payable by such Person at such time);

provided, *however*, that any indebtedness which has been defeased in accordance with GAAP or defeased pursuant to the deposit of cash or Cash Equivalents (in an amount sufficient to satisfy all such indebtedness obligations at maturity or redemption, as applicable, and all payments of interest and premium, if any) in a trust or account created or pledged for the sole benefit of the holders of such indebtedness, and subject to no other Liens, shall not constitute "Indebtedness."

The amount of Indebtedness of any Person at any date will be the outstanding balance at such date of all unconditional obligations as described above and the maximum liability, upon the occurrence of the contingency giving rise to the obligation, of any contingent obligations at such date.

Notwithstanding the preceding, "Indebtedness" shall not include:

(1) Production Payments and Reserve Sales;

(2) any obligation of a Person in respect of a farm-in agreement or similar arrangement whereby such Person agrees to pay all or a share of the drilling, completion or other expenses of an exploratory or development well (which agreement may be subject to a maximum payment obligation, after which expenses are shared in accordance with the working or participation interest therein or in accordance with the agreement of the parties) or perform the drilling, completion or other operation on such well in exchange for an ownership interest in an oil or gas property;

(3) any obligations under Currency Agreements, Commodity Agreements and Interest Rate Agreements; *provided* that such Agreements are entered into for bona fide hedging purposes of the Parent Guarantor or its Restricted Subsidiaries (as determined in good faith by the Board of Directors or senior management of the Parent Guarantor, whether or not accounted for as a hedge in accordance with GAAP) and, in the case of Currency Agreements or Commodity Agreements, such Currency Agreements or Commodity Agreements are related to business transactions of the Parent Guarantor or its Restricted Subsidiaries entered into in the ordinary course of business and, in the case of Interest Rate Agreements, such Interest Rate Agreements substantially correspond in terms of notional amount, duration and interest rates, as applicable, to Indebtedness of the Parent Guarantor or its Restricted Subsidiaries Incurred without violation of the Indenture;

(4) any obligation arising from agreements of the Parent Guarantor or a Restricted Subsidiary providing for indemnification, guarantees, adjustment of purchase price, holdbacks, contingency payment obligations or similar obligations, in each case, Incurred or assumed in connection with the acquisition or disposition of any business, assets or Capital Stock of a

Restricted Subsidiary, *provided* that such Indebtedness is not reflected on the face of the balance sheet of the Parent Guarantor or any Restricted Subsidiary;

(5) any obligation arising from the honoring by a bank or other financial institution of a check, draft or similar instrument (including daylight overdrafts) drawn against insufficient funds in the ordinary course of business, *provided* that such Indebtedness is extinguished within five business days of Incurrence;

(6) in-kind obligations relating to net oil or natural gas balancing positions arising in the ordinary course of business;

(7) all contracts and other obligations, agreements, instruments or arrangements described in clauses (19), (20), (21) or (28)(a) of the definition of "Permitted Liens;" and

(8) accrued expenses and trade payables and other accrued liabilities arising in the ordinary course of business that are not overdue by 90 days past the invoice or billing date or more or are being contested in good faith by appropriate proceedings promptly instituted and diligently conducted.

In addition, "Indebtedness" of any Person shall include Indebtedness described in the first paragraph of this definition of "Indebtedness" that would not appear as a liability on the balance sheet of such Person if:

(1) such Indebtedness is the obligation of a partnership or joint venture that is not a Restricted Subsidiary (a "Joint Venture");

(2) such Person or a Restricted Subsidiary of such Person is a general partner of the Joint Venture or otherwise liable for all or a portion of the Joint Venture's liabilities (a "General Partner"); and

(3) there is recourse, by contract or operation of law, with respect to the payment of such Indebtedness to property or assets of such Person or a Restricted Subsidiary of such Person; and then such Indebtedness shall be included in an amount not to exceed:

(a) the lesser of (i) the net assets of the General Partner and (ii) the amount of such obligations to the extent that there is recourse, by contract or operation of law, to the property or assets of such Person or a Restricted Subsidiary of such Person; or

(b) if less than the amount determined pursuant to clause (a) immediately above, the actual amount of such Indebtedness that is with recourse to such Person or a Restricted Subsidiary of such Person, if the Indebtedness is evidenced by a writing and is for a determinable amount and the related interest expense shall be included in Consolidated Interest Expense to the extent actually paid by such Person and its Restricted Subsidiaries.

"*Interest Rate Agreement*" means with respect to any Person any interest rate protection agreement, interest rate future agreement, interest rate option agreement, interest rate swap agreement, interest rate cap agreement, interest rate collar agreement, interest rate hedge agreement or other similar agreement or arrangement as to which such Person is party or a beneficiary.

"*Investment*" means, with respect to any Person, all investments by such Person in other Persons (including Affiliates) in the form of any direct or indirect advance, loan or other extensions of credit (including by way of guarantee or similar arrangement, but excluding any debt or extension of credit represented by a bank deposit other than a time deposit and advances or extensions of credit to customers in the ordinary course of business) or capital contribution to (by means of any transfer of cash or other property to others or any payment for property or services for the account or use of others), or any purchase or acquisition of Capital Stock, Indebtedness or other similar instruments (excluding any interest in a crude oil or natural gas leasehold to the extent constituting a security under applicable law) issued by, such other Person and all other items that are or would be classified as investments on a balance sheet prepared in accordance with GAAP; *provided* that none of the following will be deemed to be an Investment:

(1) Hedging Obligations entered into in the ordinary course of business and in compliance with the Indenture;

(2) endorsements of negotiable instruments and documents in the ordinary course of business; and

(3) an acquisition of assets, Capital Stock or other securities by the Parent Guarantor or a Subsidiary for consideration to the extent such consideration consists of Common Stock of the Parent Guarantor.

The amount of any Investment shall not be adjusted for increases or decreases in value, write-ups, write-downs or write-offs with respect to such Investment.

For purposes of the definition of " *Unrestricted Subsidiary*" and the covenant described under "—Certain Covenants—Limitation on Restricted Payments,"

(1) "Investment" will include the portion (proportionate to the Parent Guarantor's equity interest in a Restricted Subsidiary to be designated as an Unrestricted Subsidiary) of the Fair Market Value of the net assets of such Restricted Subsidiary at the time that such Restricted Subsidiary is designated an Unrestricted Subsidiary; provided, however, that upon a redesignation of such Subsidiary as a Restricted Subsidiary, the Parent Guarantor will be deemed to continue to have a permanent "Investment" in an Unrestricted Subsidiary in an amount (if positive) equal to

  (a) the Parent Guarantor's "Investment" in such Subsidiary at the time of such redesignation less

  (b) the portion (proportionate to the Parent Guarantor's equity interest in such Subsidiary) of the Fair Market Value of the net assets of such Subsidiary at the time that such Subsidiary is so re-designated a Restricted Subsidiary; and

(2) any property transferred to or from an Unrestricted Subsidiary will be valued at its Fair Market Value at the time of such transfer.

"*Investment Grade Rating*" means a rating equal to or higher than:

(1) Baa3 (or the equivalent) with a stable or better outlook by Moody's; and

(2) BBB- (or the equivalent) with a stable or better outlook by S&P,

or, if either such entity ceases to make a rating on the Notes publicly available for reasons outside of the Parent Guarantor's control, the equivalent investment grade credit rating from any other Rating Agency.

"*Investment Grade Rating Event*" means the first day on which the Notes have an Investment Grade Rating from each Rating Agency, and no Default has occurred and is then continuing under the Indenture.

"*Issue Date*" means the first date on which the Notes are issued under the Indenture, November 17, 2009.

"*Lien*" means, with respect to any asset, any mortgage, lien (statutory or otherwise), pledge, hypothecation, charge, security interest, preference, priority or encumbrance of any kind in respect of such asset, whether or not filed, recorded or otherwise perfected under applicable law, including any conditional sale or other title retention agreement, any lease in the nature thereof, any option or other agreement to sell or give a security interest in and any filing of or agreement to give any financing statement under the Uniform Commercial Code (or equivalent statutes) of any jurisdiction; *provided* that in no event shall an operating lease be deemed to constitute a Lien.

"*Minority Interest*" means the percentage interest represented by any class of Capital Stock of a Restricted Subsidiary that are not owned by the Parent Guarantor or a Restricted Subsidiary.

"*Moody's*" means Moody's Investors Service, Inc., or any successor to the rating agency business thereof.

"*Net Available Cash*" from an Asset Disposition means cash payments received (including any cash payments received by way of deferred payment of principal pursuant to a note or installment receivable or otherwise and net proceeds from the sale or other disposition of any securities received as consideration, but only as and when received, but excluding any other consideration received in the form of assumption by the acquiring Person of Indebtedness or other obligations relating to the properties or assets that are the subject of such Asset Disposition or received in any other non-cash form) therefrom, in each case net of:

(1) all legal, accounting, investment banking, title and recording tax expenses, commissions and other fees and expenses Incurred, and all federal, state, provincial, foreign and local taxes required to be paid or accrued as a liability under GAAP (after taking into account any available tax credits or deductions and any tax sharing agreements), as a consequence of such Asset Disposition;

(2) all payments made on any Indebtedness or Hedging Obligation which is secured by any assets subject to such Asset Disposition, in accordance with the terms of any Lien upon such assets, or which must by its terms, or in order to obtain a necessary consent to such Asset Disposition, or by applicable law be repaid out of the proceeds from such Asset Disposition;

(3) all distributions and other payments required to be made to minority interest holders in Subsidiaries or joint ventures or to holders of royalty or similar interests as a result of such Asset Disposition;

(4) the deduction of appropriate amounts to be provided by the seller as a reserve, in accordance with GAAP, against any liabilities associated with the assets disposed of in such Asset Disposition and retained by the Parent Guarantor or any Restricted Subsidiary after such Asset Disposition; and

(5) all relocation expenses incurred as a result thereof and all related severance and associated costs, expenses and charges of personnel related to assets and related operations disposed of;

provided, however, that if any consideration for an Asset Disposition (that would otherwise constitute Net Available Cash) is required to be held in escrow pending determination of whether or not a purchase price adjustment will be made, such consideration (or any portion thereof) shall become Net Available Cash only at such time as it is released to the Parent Guarantor or any of its Restricted Subsidiaries from escrow.

"*Net Cash Proceeds*," with respect to any issuance or sale of Capital Stock or any contribution to equity capital, means the cash proceeds of such issuance, sale or contribution net of attorneys' fees, accountants' fees, underwriters' or placement agents' fees, listing fees, discounts or commissions and brokerage, consultant and other fees and charges actually Incurred in connection with such issuance, sale or contribution and net of taxes paid or payable as a result of such issuance or sale (after taking into account any available tax credit or deductions and any tax sharing arrangements).

"*Net Working Capital*" means (a) the sum of (i) all current assets of the Parent Guarantor and its Restricted Subsidiaries, except current assets from commodity price risk management activities arising in the ordinary course of the Oil and Gas Business, plus (ii) the amount of revolving credit borrowings available to be Incurred under the Senior Secured Credit Agreement, less (b) all current liabilities of the Parent Guarantor and its Restricted Subsidiaries, except current liabilities (i) associated with asset retirement obligations relating to Oil and Gas Properties, (ii) included in Indebtedness and (iii) any current liabilities from commodity price risk management activities arising in the ordinary course of the Oil and Gas Business, in each case as set forth in the consolidated financial statements of the Parent Guarantor prepared in accordance with GAAP.

"*Non-Recourse Debt*" means Indebtedness of a Person:

(1) as to which neither the Parent Guarantor nor any Restricted Subsidiary (a) provides any Guarantee or credit support of any kind (including any undertaking, guarantee, indemnity, agreement or instrument that would constitute Indebtedness) or (b) is directly or indirectly liable (as a guarantor or otherwise);

(2) no default with respect to which (including any rights that the holders thereof may have to take enforcement action against an Unrestricted Subsidiary) would permit (upon notice, lapse of time or both) any holder of any other Indebtedness of the Parent Guarantor or any Restricted Subsidiary to declare a default under such other Indebtedness or cause the payment thereof to be accelerated or payable prior to its stated maturity; and

(3) the explicit terms of which provide there is no recourse against any of the assets of the Parent Guarantor or its Restricted Subsidiaries.

"*Officer*" means the Chairman of the Board, the Chief Executive Officer, the President, the Chief Financial Officer, any Vice President, the Treasurer or the Secretary of the Issuer. Officer of any Guarantor has a correlative meaning.

"*Officers' Certificate*" means a certificate signed by two Officers of the Issuer.

"*Oil and Gas Business*" means:

(1) the business of acquiring, exploring, exploiting, developing, producing, operating and disposing of interests in oil, natural gas, liquefied natural gas and other Hydrocarbon and mineral properties or products produced in association with any of the foregoing;

(2) the business of gathering, marketing, distributing, treating, processing, storing, refining, selling and transporting of any production from such interests or properties and products produced in association therewith and the marketing of oil, natural gas, other Hydrocarbons and minerals obtained from unrelated Persons;

(3) any other related energy business, including power generation and electrical transmission business, directly or indirectly, from oil, natural gas and other Hydrocarbons and minerals produced substantially from properties in which the Parent Guarantor or its Restricted Subsidiaries, directly or indirectly, participate;

(4) any business relating to oil field sales and service; and

(5) any business or activity relating to, arising from, or necessary, appropriate or incidental to the activities described in the foregoing clauses (1) through (4) of this definition.

"*Oil and Gas Properties*" means all properties, including equity or other ownership interests therein, owned by a Person which contain or are believed to contain oil and gas reserves.

"*Opinion of Counsel*" means a written opinion from legal counsel who is acceptable to the Trustee. The counsel may be an employee of or counsel to the Issuer, a Guarantor or the Trustee.

"*Parent Guarantee*" means the guarantee of payment of the Notes by the Parent Guarantor pursuant to the terms of the Indenture.

"*Pari Passu Indebtedness*" means any Indebtedness of the Issuer or any Guarantor that ranks equally in right of payment to the Notes or the Guarantees, as the case may be.

"*Permitted Acquisition Indebtedness*" means Indebtedness (including Disqualified Stock) of the Parent Guarantor or any of the Restricted Subsidiaries to the extent such Indebtedness was Indebtedness:

(1) of an acquired Person prior to the date on which such Person became a Restricted Subsidiary as a result of having been acquired and not incurred in contemplation of such acquisition; or

(2) of a Person that was merged, consolidated or amalgamated with or into the Parent Guarantor or a Restricted Subsidiary that was not incurred in contemplation of such merger, consolidation or amalgamation,

provided that on the date such Person became a Restricted Subsidiary or the date such Person was merged, consolidated and amalgamated with or into the Parent Guarantor or a Restricted Subsidiary, as applicable, after giving pro forma effect thereto,

(a) the Restricted Subsidiary or the Parent Guarantor, as applicable, would be permitted to incur at least $1.00 of additional Indebtedness pursuant to the Consolidated Coverage Ratio test described under "—Certain Covenants—Limitation on Indebtedness and Preferred Stock," or

(b) the Consolidated Coverage Ratio for the Parent Guarantor would be greater than the Consolidated Coverage Ratio for the Parent Guarantor immediately prior to such transaction.

"*Permitted Business Investment*" means any Investment made in the ordinary course of, and of a nature that is or shall have become customary in, the Oil and Gas Business including investments or expenditures for actively exploiting, exploring for, acquiring, developing, producing, processing, gathering, marketing or transporting oil, natural gas or other Hydrocarbons and minerals through agreements, transactions, interests or arrangements which permit one to share risks or costs, comply with regulatory requirements regarding local ownership or satisfy other objectives customarily achieved through the conduct of the Oil and Gas Business jointly with third parties including:

(1) ownership interests in oil, natural gas, other Hydrocarbons and minerals properties, liquefied natural gas facilities, processing facilities, gathering systems, pipelines, storage facilities or related systems or ancillary real property interests;

(2) Investments in the form of or pursuant to operating agreements, working interests, royalty interests, mineral leases, processing agreements, farm-in agreements, farm-out agreements, contracts for the sale, transportation or exchange of oil, natural gas, other Hydrocarbons and minerals, production sharing agreements, participation agreements, development agreements, area of mutual interest agreements, unitization agreements, pooling agreements, joint bidding agreements, service contracts, joint venture agreements, partnership agreements (whether general or limited), subscription agreements, stock purchase agreements, stockholder agreements and other similar agreements (including for limited liability companies) with third parties; and

(3) direct or indirect ownership interests in drilling rigs and related equipment, including, without limitation, transportation equipment.

"*Permitted Holder*" means each of (i) Warburg Pincus & Co.; (ii) Paul M. Rady ("Rady"); (iii) Glen C. Warren, Jr. ("Warren"); (iv) Rady's wife or Warren's wife; (v) any lineal descendant of either Rady or Warren; (vi) the guardian or other legal representative of either Rady or Warren; (vii) the estate of either Rady or Warren; (viii) any trust of which at least one of the trustees is either Rady or Warren, or the principal beneficiaries of which are any one or more of the Persons referred to in the preceding clauses (ii) through (vii); (ix) any Person that is controlled by any one or more of the Persons in the preceding clauses (i) through (viii); and (x) any group (within the meaning of the Exchange Act) that includes one or more of the Persons described in the preceding clauses (i) through (ix), *provided* that such Persons described in the preceding clauses (i) through (ix) control more than 50% of the total voting power of such group.

"*Permitted Investment*" means an Investment by the Parent Guarantor or any Restricted Subsidiary in:

(1) the Parent Guarantor, a Restricted Subsidiary or a Person which will, upon the making of such Investment, become a Restricted Subsidiary; *provided*, *however*, that the primary business of such Restricted Subsidiary is the Oil and Gas Business;

(2) another Person whose primary business is the Oil and Gas Business if as a result of such Investment such other Person becomes a Restricted Subsidiary or is merged or consolidated with or into, or transfers or conveys all or substantially all its assets to, the Parent Guarantor or a Restricted Subsidiary and, in each case, any Investment held by such Person; *provided* that such Investment was not acquired by such Person in contemplation of such acquisition, merger, consolidation or transfer;

(3) cash and Cash Equivalents;

(4) receivables owing to the Parent Guarantor or any Restricted Subsidiary created or acquired in the ordinary course of business and payable or dischargeable in accordance with customary trade terms; *provided*, *however*, that such trade terms may include such concessionary trade terms as the Parent Guarantor or any such Restricted Subsidiary deems reasonable under the circumstances;

(5) payroll, commission, travel, relocation and similar advances to cover matters that are expected at the time of such advances ultimately to be treated as expenses for accounting purposes and that are made in the ordinary course of business;

(6) loans or advances to employees (other than executive officers) made in the ordinary course of business consistent with past practices of the Parent Guarantor or such Restricted Subsidiary;

(7) Capital Stock, obligations or securities received in settlement of debts (x) created in the ordinary course of business and owing to the Parent Guarantor or any Restricted Subsidiary or in satisfaction of judgments or (y) pursuant to any plan of reorganization or similar arrangement in a bankruptcy or insolvency proceeding;

(8) any Person as a result of the receipt of non-cash consideration from an Asset Disposition that was made pursuant to and in compliance with the covenant described under "Certain Covenants—Limitation on Sales of Assets and Subsidiary Stock";

(9) Investments in existence on the Issue Date;

(10) Commodity Agreements, Currency Agreements, Interest Rate Agreements and related Hedging Obligations, which transactions or obligations are Incurred in compliance with "—Certain Covenants—Limitation on Indebtedness and Preferred Stock";

(11) Guarantees issued in accordance with the covenant described under "—Certain Covenants—Limitation on Indebtedness and Preferred Stock";

(12) Permitted Business Investments;

(13) any Person where such Investment was acquired by the Parent Guarantor or any of its Restricted Subsidiaries (a) in exchange for any other Investment or accounts receivable held by the Parent Guarantor or any such Restricted Subsidiary in connection with or as a result of a bankruptcy, workout, reorganization or recapitalization of the issuer of such other Investment or accounts receivable or (b) as a result of a foreclosure by the Parent Guarantor or any of its Restricted Subsidiaries with respect to any secured Investment or other transfer of title with respect to any secured Investment in default;

(14) any Person to the extent such Investments consist of prepaid expenses, negotiable instruments held for collection and lease, utility and workers' compensation, performance and other similar deposits made in the ordinary course of business by the Parent Guarantor or any Restricted Subsidiary;

(15) Guarantees of performance or other obligations (other than Indebtedness) arising in the ordinary course in the Oil and Gas Business, including obligations under oil and natural gas exploration, development, joint operating, and related agreements and licenses, concessions or operating leases related to the Oil and Gas Business;

(16) Investments in the Notes; and

(17) Investments by the Parent Guarantor or any of its Restricted Subsidiaries, together with all other Investments pursuant to this clause (17), in an aggregate amount outstanding at the time of such Investment not to exceed the greater of $10.0 million and 1.0% of the Parent Guarantor's Adjusted Consolidated Net Tangible Assets (with the Fair Market Value of such Investment being measured at the time such Investment is made and without giving effect to subsequent changes in value).

"*Permitted Liens*" means, with respect to any Person:

(1) Liens securing Indebtedness under a Credit Facility permitted to be Incurred under the Indenture;

(2) pledges or deposits by such Person under workers' compensation laws, unemployment insurance laws, social security or old age pension laws or similar legislation, or good faith deposits in connection with bids, tenders, contracts (other than for the payment of Indebtedness) or leases to which such Person is a party, or deposits (which may be secured by a Lien) to secure public or statutory obligations of such Person including letters of credit and bank guarantees required or requested by the United States, any State thereof or any foreign government or any subdivision, department, agency, organization or instrumentality of any of the foregoing in connection with any contract or statute (including lessee or operator obligations under statutes, governmental regulations, contracts or instruments related to the ownership, exploration and production of oil, natural gas, other hydrocarbons and minerals on State, Federal or foreign lands or waters), or deposits of cash or United States government bonds to secure indemnity performance, surety or appeal bonds or other similar bonds to which such Person is a party, or deposits as security for contested taxes or import or customs duties or for the payment of rent, in each case Incurred in the ordinary course of business;

(3) statutory and contractual Liens of landlords and Liens imposed by law, including carriers', warehousemen's, mechanics', materialmen's and repairmen's Liens, in each case for sums not yet due or being contested in good faith by appropriate proceedings if a reserve or other appropriate provisions, if any, as shall be required by GAAP shall have been made in respect thereof;

(4) Liens for taxes, assessments or other governmental charges or claims not yet subject to penalties for non-payment or which are being contested in good faith by appropriate

proceedings; *provided* that appropriate reserves, if any, required pursuant to GAAP have been made in respect thereof;

(5) Liens in favor of issuers of surety or performance bonds or bankers' acceptances issued pursuant to the request of and for the account of such Person in the ordinary course of its business;

(6) survey exceptions, encumbrances, ground leases, easements or reservations of, or rights of others for, licenses, rights of way, sewers, electric lines, telegraph and telephone lines and other similar purposes, or zoning, building codes or other restrictions (including, without limitation, minor defects or irregularities in title and similar encumbrances) as to the use of real properties or Liens incidental to the conduct of the business of such Person or to the ownership of its properties which do not in the aggregate materially adversely affect the value of the assets of such Person and its Restricted Subsidiaries, taken as a whole, or materially impair their use in the operation of the business of such Person;

(7) Liens securing Hedging Obligations;

(8) leases, licenses, subleases and sublicenses of assets (including, without limitation, real property and intellectual property rights) which do not materially interfere with the ordinary conduct of the business of the Parent Guarantor or any of its Restricted Subsidiaries;

(9) prejudgment Liens and judgment Liens not giving rise to an Event of Default so long as such Lien is adequately bonded and any appropriate legal proceedings which may have been duly initiated for the review of such judgment have not been finally terminated or the period within which such proceedings may be initiated has not expired;

(10) Liens for the purpose of securing the payment of all or a part of the purchase price of, or Capitalized Lease Obligations, purchase money obligations or other payments Incurred to finance the acquisition, lease, improvement or construction of or repairs or additions to, assets or property acquired or constructed in the ordinary course of business; *provided* that:

(a) the aggregate principal amount of Indebtedness secured by such Liens is otherwise permitted to be Incurred under the Indenture and does not exceed the cost of the assets or property so acquired or constructed; and

(b) such Liens are created within 360 days of the later of the acquisition, lease, completion of improvements, construction, repairs or additions or commencement of full operation of the assets or property subject to such Lien and do not encumber any other assets or property of the Parent Guarantor or any Restricted Subsidiary other than such assets or property and assets affixed or appurtenant thereto;

(11) Liens arising solely by virtue of any statutory or common law provisions relating to banker's Liens, rights of set-off or similar rights and remedies as to deposit accounts or other funds maintained with a depositary institution; *provided* that:

(a) such deposit account is not a dedicated cash collateral account and is not subject to restrictions against access by the Parent Guarantor in excess of those set forth by regulations promulgated by the Federal Reserve Board; and

(b) such deposit account is not intended by the Parent Guarantor or any Restricted Subsidiary to provide collateral to the depository institution;

(12) Liens arising from Uniform Commercial Code financing statement filings regarding operating leases entered into by the Parent Guarantor and its Restricted Subsidiaries in the ordinary course of business;

(13) Liens existing on the Issue Date;

(14) Liens on property or shares of Capital Stock of a Person at the time such Person becomes a Subsidiary; *provided*, *however*, that such Liens are not created or Incurred in connection with, or in contemplation of, such other Person becoming a Subsidiary; *provided further*, however, that any such Lien may not extend to any other property owned by the Parent Guarantor or any Restricted Subsidiary (other than assets or property affixed or appurtenant thereto);

(15) Liens on property at the time the Parent Guarantor or any of its Subsidiaries acquired the property, including any acquisition by means of a merger or consolidation with or into the Parent Guarantor or any of its Subsidiaries; *provided*, *however*, that such Liens are not created or Incurred in connection with, or in contemplation of, such acquisition; *provided further*, *however*, that such Liens may not extend to any other property owned by the Parent Guarantor or any Restricted Subsidiary (other than assets or property affixed or appurtenant thereto);

(16) Liens securing the Notes, Subsidiary Guarantees and other obligations under the Indenture;

(17) Liens securing Refinancing Indebtedness Incurred to refinance Indebtedness that was previously so secured, *provided* that any such Lien is limited to all or part of the same property or assets (plus improvements, accessions, proceeds or dividends or distributions in respect thereof) that secured (or, under the written arrangements under which the original Lien arose, could secure) the Indebtedness being refinanced or is in respect of property or assets that is the security for a Permitted Lien hereunder;

(18) any interest or title of a lessor under any Capitalized Lease Obligation or operating lease;

(19) Liens in respect of Production Payments and Reserve Sales, which Liens shall be limited to the property that is the subject of such Production Payments and Reserve Sales;

(20) Liens arising under farm-out agreements, farm-in agreements, division orders, contracts for the sale, purchase, exchange, transportation, gathering or processing of Hydrocarbons, unitizations and pooling designations, declarations, orders and agreements, development agreements, joint venture agreements, partnership agreements, operating agreements, royalties, working interests, net profits interests, joint interest billing arrangements, participation agreements, production sales contracts, area of mutual interest agreements, gas balancing or deferred production agreements, injection, repressuring and recycling agreements, salt water or other disposal agreements, seismic or geophysical permits or agreements, and other agreements which are customary in the Oil and Gas Business; *provided*, *however*, in all instances that such Liens are limited to the assets that are the subject of the relevant agreement, program, order or contract;

(21) Liens on pipelines or pipeline facilities that arise by operation of law;

(22) Liens securing Indebtedness in an aggregate principal amount outstanding at any one time, added together with all other Indebtedness secured by Liens Incurred pursuant to this clause (22), not to exceed the greater of $10.0 million and 1.0% of the Parent Guarantor's Adjusted Consolidated Net Tangible Assets, as determined on the date of Incurrence of such Indebtedness after giving pro forma effect to such Incurrence and the application of the proceeds therefrom;

(23) Liens in favor of the Parent Guarantor, the Issuer or any Subsidiary Guarantor;

(24) deposits made in the ordinary course of business to secure liability to insurance carriers;

(25) Liens in favor of customs and revenue authorities arising as a matter of law to secure payment of customs duties in connection with the importation of goods in the ordinary course of business;

(26) Liens deemed to exist in connection with Investments in repurchase agreements permitted under "—Certain Covenants—Limitation on Indebtedness and Preferred Stock"; *provided* that such Liens do not extend to any assets other than those that are the subject of such repurchase agreement;

(27) Liens encumbering reasonable customary initial deposits and margin deposits and similar Liens attaching to commodity trading accounts or other brokerage accounts incurred in the ordinary course of business and not for speculative purposes;

(28) any (a) interest or title of a lessor or sublessor under any lease, liens reserved in oil, gas or other Hydrocarbons, minerals, leases for bonus, royalty or rental payments and for compliance with the terms of such leases; (b) restriction or encumbrance that the interest or title of such lessor or sublessor may be subject to (including, without limitation, ground leases or other prior leases of the demised premises, mortgages, mechanics' liens, tax liens, and easements); or (c) subordination of the interest of the lessee or sublessee under such lease to any restrictions or encumbrance referred to in the preceding clause (b);

(29) Liens upon specific items of inventory or other goods and proceeds of any Person securing such Person's obligations in respect of bankers' acceptances issued or created for the account of such Person to facilitate the purchase, shipment or storage of such inventory or other goods;

(30) Liens arising under the Indenture in favor of the Trustee for its own benefit and similar Liens in favor of other trustees, agents and representatives arising under instruments governing Indebtedness permitted to be incurred under the Indenture, *provided*, *however*, that such Liens are solely for the benefit of the trustees, agents or representatives in their capacities as such and not for the benefit of the holders of such Indebtedness;

(31) Liens arising from the deposit of funds or securities in trust for the purpose of decreasing or defeasing Indebtedness so long as such deposit of funds or securities and such decreasing or defeasing of Indebtedness are permitted under the covenant described under "—Certain Covenants—Limitation on Restricted Payments"; and

(32) Liens in favor of collecting or payer banks having a right of setoff, revocation, or charge back with respect to money or instruments of the Parent Guarantor or any Subsidiary of the Parent Guarantor on deposit with or in possession of such bank.

In each case set forth above, notwithstanding any stated limitation on the assets that may be subject to such Lien, a Permitted Lien on a specified asset or group or type of assets may include Liens on all improvements, additions and accessions thereto and all products and proceeds thereof (including dividends, distributions and increases in respect thereof).

"*Person*" means any individual, corporation, partnership, joint venture, association, joint-stock company, trust, unincorporated organization, limited liability company, government or any agency or political subdivision thereof or any other entity.

"*Preferred Stock*," as applied to the Capital Stock of any corporation, means Capital Stock of any class or classes (however designated) which is preferred as to the payment of dividends, or as to the distribution of assets upon any voluntary or involuntary liquidation or dissolution of such corporation, over shares of Capital Stock of any other class of such corporation.

"*Production Payments and Reserve Sales*" means the grant or transfer by the Parent Guarantor or a Restricted Subsidiary to any Person of a royalty, overriding royalty, net profits interest, production payment (whether volumetric or dollar denominated), partnership or other interest in Oil and Gas Properties, reserves or the right to receive all or a portion of the production or the proceeds from the sale of production attributable to such properties where the holder of such interest has recourse solely to such production or proceeds of production, subject to the obligation of the grantor or transferor to operate and maintain, or cause the subject interests to be operated and maintained, in a reasonably prudent manner or other customary standard or subject to the obligation of the grantor or transferor to indemnify for environmental, title or other matters customary in the Oil and Gas Business, including any such grants or transfers pursuant to incentive compensation programs on terms that are reasonably customary in the Oil and Gas Business for geologists, geophysicists or other providers of technical services to the Parent Guarantor or a Restricted Subsidiary.

"*Rating Agency*" means each of S&P and Moody's, or if S&P or Moody's or both shall not make a rating on the Notes publicly available, a nationally recognized statistical rating agency or agencies, as the case may be, selected by the Parent Guarantor (as certified by a resolution of the Board of Directors) which shall be substituted for S&P or Moody's, or both, as the case may be.

"*Refinancing Indebtedness*" means Indebtedness that is Incurred to refund, refinance, replace, exchange, renew, repay, extend, prepay, redeem or retire (including pursuant to any defeasance or discharge mechanism) (collectively, "refinance" and "refinances" and "refinanced" shall have correlative meanings) any Indebtedness (including Indebtedness of the Parent Guarantor that refinances Indebtedness of any Restricted Subsidiary and Indebtedness of any Restricted Subsidiary that refinances Indebtedness of another Restricted Subsidiary, but excluding Indebtedness of a Subsidiary that is not a Restricted Subsidiary that refinances Indebtedness of the Parent Guarantor or a Restricted Subsidiary), including Indebtedness that refinances Refinancing Indebtedness, *provided*, *however*, that:

(1) (a) if the Stated Maturity of the Indebtedness being Refinanced is earlier than the Stated Maturity of the Notes, the Refinancing Indebtedness has a Stated Maturity no earlier than the Stated Maturity of the Indebtedness being refinanced or (b) if the Stated Maturity of the Indebtedness being refinanced is later than the Stated Maturity of the Notes, the Refinancing Indebtedness has a Stated Maturity at least 91 days later than the Stated Maturity of the Notes;

(2) the Refinancing Indebtedness has an Average Life at the time such Refinancing Indebtedness is Incurred that is equal to or greater than the Average Life of the Indebtedness being refinanced;

(3) such Refinancing Indebtedness is Incurred in an aggregate principal amount (or if issued with original issue discount, an aggregate issue price) that is equal to or less than the sum of the aggregate principal amount (or if issued with original issue discount, the aggregate accreted value) then outstanding of the Indebtedness being refinanced (plus, without duplication, any additional Indebtedness Incurred to pay interest, premiums or defeasance costs required by the instruments governing such existing Indebtedness and fees and expenses Incurred in connection therewith); and

(4) if the Indebtedness being Refinanced is subordinated in right of payment to the Notes or the Subsidiary Guarantee, such Refinancing Indebtedness is subordinated in right of payment to the Notes or the Subsidiary Guarantee on terms at least as favorable to the holders as those contained in the documentation governing the Indebtedness being Refinanced.

"*Registration Rights Agreement*" means that certain registration rights agreement dated as of the Issue Date by and among the Issuer, the Guarantors and the initial purchasers set forth therein and, with respect to any Additional Notes, one or more substantially similar registration rights agreements among the Issuer and the other parties thereto, as any such agreement may be amended from time to time.

"*Reporting Failure*" means the failure of the Parent Guarantor to file with the SEC and make available or otherwise deliver to the Trustee and each holder of Notes, within the time periods specified in "—Certain Covenants—Provision of Financial Information" (after giving effect to any grace period specified under Rule 12b-25 under the Exchange Act), the periodic reports, information, documents or other reports which the Parent Guarantor may be required to file with the SEC pursuant to such provision.

"*Restricted Investment*" means any Investment other than a Permitted Investment.

"*Restricted Subsidiary*" means any Subsidiary of the Parent Guarantor other than an Unrestricted Subsidiary.

"*S&P*" means Standard & Poor's Rating Services, a division of The McGraw-Hill Companies, Inc., or any successor to the rating agency business thereof.

"*Sale/Leaseback Transaction*" means an arrangement relating to property now owned or hereafter acquired whereby the Parent Guarantor or a Restricted Subsidiary transfers such property to a Person and the Parent Guarantor or a Restricted Subsidiary leases it from such Person.

"*SEC*" means the United States Securities and Exchange Commission.

"*Senior Secured Credit Agreement*" means the Third Amended and Restated Credit Agreement dated as of January 14, 2009 among Antero Resources Corporation, Antero Resources Midstream Corporation, Antero Resources Piceance Corporation, Antero Resources Pipeline Corporation and Antero Resources Appalachian Corporation, as borrowers and guarantors, Antero Resources Finance Corporation, as guarantor, JPMorgan Chase Bank, N.A., as administrative agent, BNP Paribas and Bank of Scotland plc, as co-syndication agents, Union Bank, N.A., as documentation agent, and the lenders parties thereto from time to time, including any guarantees, collateral documents, instruments and agreements executed in connection therewith, and any amendments, supplements, modifications, extensions, renewals, restatements, refundings or refinancings thereof and any indentures or credit facilities or commercial paper facilities with banks or other institutional lenders or investors that replace, refund or refinance any part of the loans, notes, other credit facilities or commitments thereunder, including any such replacement, refunding or refinancing facility or indenture that increases the amount borrowable thereunder or alters the maturity thereof (*provided* that such increase in borrowings is permitted under "—Certain Covenants—Limitation on Indebtedness and Preferred Stock" above).

"*Significant Subsidiary*" means any Restricted Subsidiary that would be a "Significant Subsidiary" of the Parent Guarantor within the meaning of Rule 1-02 under Regulation S-X promulgated by the SEC, as in effect on the Issue Date.

"*Stated Maturity*" means, with respect to any security, the date specified in such security as the fixed date on which the payment of principal of such security is due and payable, including pursuant to any mandatory redemption provision, but shall not include any contingent obligations to repay, redeem or repurchase any such principal prior to the date originally scheduled for the payment thereof.

"*Subordinated Obligation*" means any Indebtedness of the Issuer (whether outstanding on the Issue Date or thereafter Incurred) which is expressly subordinated in right of payment to the Notes pursuant to a written agreement.

"*Subsidiary*" of any Person means (a) any corporation, association or other business entity (other than a partnership, joint venture, limited liability company or similar entity) of which more than 50% of the total ordinary voting power of shares of Capital Stock entitled (without regard to the occurrence of any contingency) to vote in the election of directors, managers or trustees thereof (or Persons performing similar functions) or (b) any partnership, joint venture, limited liability company or similar entity of which more than 50% of the capital accounts, distribution rights, total equity and voting interests or general or limited partnership interests, as applicable, is, in the case of clauses (a) and (b), at the time owned or controlled, directly or indirectly, by (1) such Person, (2) such Person and one or more Subsidiaries of such Person or (3) one or more Subsidiaries of such Person. Unless otherwise specified herein, each reference to a Subsidiary (other than in this definition) will refer to a Subsidiary of the Parent Guarantor.

"*Subsidiary Guarantee*" means, individually, any guarantee of payment of the Notes by a Subsidiary Guarantor pursuant to the terms of the Indenture and any supplemental indenture thereto, and, collectively, all such guarantees.

"*Subsidiary Guarantors*" means any Subsidiary of the Parent Guarantor that is a guarantor of the Notes, including any Person that is required after the Issue Date to guarantee the Notes pursuant to the "Future subsidiary guarantors" covenant, in each case until a successor replaces such Person pursuant to the applicable provisions of the Indenture and, thereafter, means such successor; *provided, however*, that the Issuer shall not be a Subsidiary Guarantor.

"*Unrestricted Subsidiary*" means:

(1) any Subsidiary of the Parent Guarantor (other than the Issuer) that at the time of determination shall be designated an Unrestricted Subsidiary by the Board of Directors of the Parent Guarantor in the manner provided below; and

(2) any Subsidiary of an Unrestricted Subsidiary.

The Board of Directors of the Parent Guarantor may designate any Subsidiary of the Parent Guarantor (including any newly acquired or newly formed Subsidiary or a Person becoming a Subsidiary through merger or consolidation or Investment therein) to be an Unrestricted Subsidiary only if:

(1) such Subsidiary or any of its Subsidiaries does not own any Capital Stock or Indebtedness of or have any Investment in, or own or hold any Lien on any property of, any other Subsidiary of the Parent Guarantor which is not a Subsidiary of the Subsidiary to be so designated or otherwise an Unrestricted Subsidiary;

(2) all the Indebtedness of such Subsidiary and its Subsidiaries shall, at the date of designation, and will at all times thereafter, consist of Non-Recourse Debt;

(3) on the date of such designation, such designation and the Investment of the Parent Guarantor or a Restricted Subsidiary in such Subsidiary complies with "—Certain Covenants—Limitation on Restricted Payments";

(4) such Subsidiary is a Person with respect to which neither the Parent Guarantor nor any of its Restricted Subsidiaries has any direct or indirect obligation to subscribe for additional Capital Stock of such Person;

(5) such Subsidiary, either alone or in the aggregate with all other Unrestricted Subsidiaries, does not operate, directly or indirectly, all or substantially all of the business of the Parent Guarantor and its Subsidiaries; and

(6) on the date such Subsidiary is designated an Unrestricted Subsidiary, such Subsidiary is not a party to any agreement, contract, arrangement or understanding with the Parent Guarantor or any Restricted Subsidiary with terms substantially less favorable to the Parent Guarantor or such Restricted Subsidiary than those that might have been obtained from Persons who are not Affiliates of the Parent Guarantor.

Any such designation by the Board of Directors of the Parent Guarantor shall be evidenced to the Trustee by filing with the Trustee a resolution of the Board of Directors of the Parent Guarantor giving effect to such designation and an Officers' Certificate certifying that such designation complies with the foregoing conditions. If, at any time, any Unrestricted Subsidiary would fail to meet the foregoing requirements as an Unrestricted Subsidiary, it shall thereafter cease to be an Unrestricted Subsidiary for purposes of the Indenture and any Indebtedness of such Subsidiary shall be deemed to be Incurred as of such date.

The Board of Directors of the Parent Guarantor may designate any Unrestricted Subsidiary to be a Restricted Subsidiary; *provided* that immediately after giving effect to such designation, no Default or Event of Default shall have occurred and be continuing or would occur as a consequence thereof and the Parent Guarantor could Incur at least $1.00 of additional Indebtedness under the first paragraph of the covenant described under "—Certain Covenants—Limitation on Indebtedness and Preferred Stock" on a pro forma basis taking into account such designation.

"*U.S. Government Obligations*" means securities that are (a) direct obligations of the United States of America for the timely payment of which its full faith and credit is pledged or (b) obligations of a Person controlled or supervised by and acting as an agency or instrumentality of the United States of America the timely payment of which is unconditionally guaranteed as a full faith and credit obligation of the United States of America, which, in either case, are not callable or redeemable at the option of the issuer thereof, and shall also include a depositary receipt issued by a bank (as defined in Section 3(a)(2) of the Securities Act), as custodian with respect to any such U.S. Government Obligations or a specific payment of principal of or interest on any such U.S. Government Obligations held by such custodian for the account of the holder of such depositary receipt; *provided* that (except as required by law) such custodian is not authorized to make any deduction from the amount payable to the holder of such depositary receipt from any amount received by the custodian in respect of the U.S. Government Obligations or the specific payment of principal of or interest on the U.S. Government Obligations evidenced by such depositary receipt.

"*Volumetric Production Payments*" means production payment obligations recorded as deferred revenue in accordance with GAAP, together with all undertakings and obligations in connection therewith.

"*Voting Stock*" of an entity means all classes of Capital Stock of such entity then outstanding and normally entitled to vote in the election of members of such entity's Board of Directors.

"*Wholly-Owned Subsidiary*" means a Restricted Subsidiary, all of the Capital Stock of which (other than directors' qualifying shares) is owned by the Parent Guarantor or another Wholly-Owned Subsidiary.

PLAN OF DISTRIBUTION

You may transfer new notes issued under the exchange offer in exchange for the old notes if:

- you acquire the new notes in the ordinary course of your business;
- you have no arrangement or understanding with any person to participate in the distribution (within the meaning of the Securities Act) of such new notes in violation of the provisions of the Securities Act; and
- you are not our "affiliate" (within the meaning of Rule 405 under the Securities Act).

Each broker-dealer that receives new notes for its own account pursuant to the exchange offer in exchange for old notes that were acquired by such broker-dealer as a result of market-making or other trading activities must acknowledge that it will deliver a prospectus in connection with any resale of such new notes. This prospectus, as it may be amended or supplemented from time to time, may be used by a broker-dealer in connection with resales of new notes received in exchange for old notes where such old notes were acquired as a result of market-making activities or other trading activities.

If you wish to exchange new notes for your old notes in the exchange offer, you will be required to make representations to us as described in "Exchange Offer—Purpose and Effect of the Exchange Offer" and "—Procedures for Tendering—Your Representations to Us" in this prospectus and in the letter of transmittal. In addition, if you are a broker-dealer who receives new notes for your own account in exchange for old notes that were acquired by you as a result of market- making activities or other trading activities, you will be required to acknowledge that you will deliver a prospectus in connection with any resale by you of such new notes.

We will not receive any proceeds from any sale of new notes by broker-dealers. New notes received by broker-dealers for their own account pursuant to the exchange offer may be sold from time to time on one or more transactions in any of the following ways:

- in the over-the-counter market;
- in negotiated transactions;
- through the writing of options on the new notes or a combination of such methods of resale;
- at market prices prevailing at the time of resale;
- at prices related to such prevailing market prices; or
- at negotiated prices.

Any such resale may be made directly to purchasers or to or through brokers or dealers who may receive compensation in the form of commissions or concessions from any such broker-dealer or the purchasers of any such new notes.

Any broker-dealer that resells new notes that were received by it for its own account pursuant to the exchange offer in exchange for old notes that were acquired by such broker-dealer as a result of market-making or other trading activities may be deemed to be an "underwriter" within the meaning of the Securities Act. The letter of transmittal states that by acknowledging that it will deliver and by delivering a prospectus, a broker-dealer will not be deemed to admit that it is an "underwriter" within the meaning of the Securities Act. We agreed to permit the use of this prospectus for a period of up to 180 days after the completion of the exchange offer by such broker-dealers to satisfy this prospectus delivery requirement. Furthermore, we agreed to amend or supplement this prospectus during such period if so requested in order to expedite or facilitate the disposition of any new notes by broker-dealers.

We have agreed to pay all expenses incident to the exchange offer other than fees and expenses of counsel to the holders and brokerage commissions and transfer taxes, if any, and will indemnify the holders of the old notes (including any broker-dealers) against certain liabilities, including liabilities under the Securities Act.

MATERIAL UNITED STATES FEDERAL TAX CONSEQUENCES

The following discussion is a summary of the material federal income tax considerations relevant to the exchange of old notes for new notes, but does not purport to be a complete analysis of all potential tax effects. The discussion is based upon the Internal Revenue Code of 1986, as amended (the "Code"), Treasury Regulations, Internal Revenue Service rulings and pronouncements and judicial decisions now in effect, all of which may be subject to change at any time by legislative, judicial or administrative action. These changes may be applied retroactively in a manner that could adversely affect a holder of new notes. Some holders, including financial institutions, insurance companies, regulated investment companies, tax-exempt organizations, dealers in securities or currencies, persons whose functional currency is not the U.S. dollar, or persons who hold the notes as part of a hedge, conversion transaction, straddle or other risk reduction transaction may be subject to special rules not discussed below. We recommend that each holder consult his own tax advisor as to the particular tax consequences of exchanging such holder's old notes for new notes, including the applicability and effect of any foreign, state, local or other tax laws or estate or gift tax considerations.

We believe that the exchange of old notes for new notes will not be an exchange or otherwise a taxable event to a holder for United States federal income tax purposes. Accordingly, a holder will not recognize gain or loss upon receipt of a new note in exchange for an old note in the exchange, and the holder's basis and holding period in the new note will be the same as its basis and holding period in the corresponding old note immediately before the exchange.

LEGAL MATTERS

The validity of the new notes offered in this exchange offer will be passed upon for us by Vinson & Elkins L.L.P., Houston, Texas.

EXPERTS

The consolidated financial statements of the Antero Resources LLC as of December 31, 2008 and 2009 and for each of the years in the three-year period ended December 31, 2009 have been included herein in reliance upon the report of KPMG LLP, independent registered public accounting firm, appearing elsewhere herein and upon the authority of such firm as experts in accounting and auditing.

Estimates of our natural gas and oil reserves, related future net cash flows and the present values thereof as of December 31, 2007, 2008 and 2009 included elsewhere in this prospectus were based in part upon reserve reports prepared by independent petroleum engineers, DeGolyer and MacNaughton, Ryder Scott Company, L.P. and Wright & Company, Inc., as applicable. We have included these estimates in reliance on the authority of such firms as experts in such matters.

ANNEX A:

LETTER OF TRANSMITTAL

**TO TENDER
OLD 9.375% SENIOR NOTES DUE 2017
OF
ANTERO RESOURCES FINANCE CORPORATION
PURSUANT TO THE EXCHANGE OFFER AND PROSPECTUS
DATED JUNE 14, 2010**

THE EXCHANGE OFFER AND WITHDRAWAL RIGHTS WILL EXPIRE AT 5:00 P.M., NEW YORK CITY TIME, ON JULY 14, 2010 (THE "EXPIRATION DATE"), UNLESS THE EXCHANGE OFFER IS EXTENDED BY THE ISSUER.

The Exchange Agent for the Exchange Offer is Wells Fargo Bank, N.A., and its contact information is as follows:

By Registered & Certified Mail:	*By Regular Mail or Overnight Courier:*	*In Person by Hand Only:*
Wells Fargo Bank, N.A. Corporate Trust Operations MAC N9303—121 PO Box 1517 Minneapolis, Minnesota 55480	Wells Fargo Bank, N.A. Corporate Trust Operations MAC N9303—121 Sixth & Marquette Avenue Minneapolis, Minnesota 55479	Wells Fargo Bank, N.A. 12th Floor—Northstar East Building Corporate Trust Operations 608 Second Avenue South Minneapolis, MN 55402

By Facsimile (for Eligible Institutions only):
(612) 667-6282

For Information or Confirmation by Telephone:
(800) 344-5128

If you wish to exchange old 9.375% Senior Notes due 2017 for an equal aggregate principal amount of new 9.375% Senior Notes due 2017 pursuant to the exchange offer, you must validly tender (and not withdraw) old notes to the Exchange Agent prior to the Expiration Date.

We refer you to the Prospectus, dated June 14, 2010 (the "Prospectus"), of Antero Resources Finance Corporation (the "Issuer"), and this Letter of Transmittal (the "Letter of Transmittal"), which together describe the Issuer's offer (the "Exchange Offer") to exchange its 9.375% Senior Notes due 2017 (the "new notes") that have been registered under the Securities Act of 1933, as amended (the "Securities Act"), for a like principal amount of its issued and outstanding 9.375% Senior Notes due 2017 (the "old notes"). Capitalized terms used but not defined herein have the respective meaning given to them in the Prospectus.

The Issuer reserves the right, at any time or from time to time, to extend the Exchange Offer at its discretion, in which event the term "Expiration Date" shall mean the latest date to which the Exchange Offer is extended. The Issuer shall notify the Exchange Agent and each registered holder of the old notes of any extension by oral or written notice prior to 9:00 a.m., New York City time, on the next business day after the previously scheduled Expiration Date.

This Letter of Transmittal is to be used by holders of the old notes. Tender of old notes is to be made according to the Automated Tender Offer Program ("ATOP") of The Depository Trust Company ("DTC") pursuant to the procedures set forth in the Prospectus under the caption "Exchange Offer—Procedures for Tendering." DTC participants that are accepting the Exchange Offer must transmit their acceptance to DTC, which will verify the acceptance and execute a book-entry delivery to the Exchange Agent's DTC account. DTC will then send a computer generated message known as an "agent's message" to the Exchange Agent for its acceptance. For you to validly tender your old notes in the Exchange Offer the Exchange Agent must receive, prior to the Expiration Date, an agent's message under the ATOP procedures that confirms that:

- DTC has received your instructions to tender your old notes; and

- you agree to be bound by the terms of this Letter of Transmittal.

BY USING THE ATOP PROCEDURES TO TENDER OLD NOTES, YOU WILL NOT BE REQUIRED TO DELIVER THIS LETTER OF TRANSMITTAL TO THE EXCHANGE AGENT. HOWEVER, YOU WILL BE BOUND BY ITS TERMS, AND YOU WILL BE DEEMED TO HAVE MADE THE ACKNOWLEDGMENTS AND THE REPRESENTATIONS AND WARRANTIES IT CONTAINS, JUST AS IF YOU HAD SIGNED IT.

PLEASE READ THE ACCOMPANYING INSTRUCTIONS CAREFULLY.

Ladies and Gentlemen:

1. By tendering old notes in the Exchange Offer, you acknowledge receipt of the Prospectus and this Letter of Transmittal.

2. By tendering old notes in the Exchange Offer, you represent and warrant that you have full authority to tender the old notes described above and will, upon request, execute and deliver any additional documents deemed by the Issuer to be necessary or desirable to complete the tender of old notes.

3. You understand that the tender of the old notes pursuant to all of the procedures set forth in the Prospectus will constitute an agreement between you and the Issuer as to the terms and conditions set forth in the Prospectus.

4. By tendering old notes in the Exchange Offer, you acknowledge that the Exchange Offer is being made in reliance upon interpretations contained in no-action letters issued to third parties by the staff of the Securities and Exchange Commission (the "SEC"), including Exxon Capital Holdings Corp., SEC No-Action Letter (available April 13, 1989), Morgan Stanley & Co., Inc., SEC No-Action Letter (available June 5, 1991) and Shearman & Sterling, SEC No-Action Letter (available July 2, 1993), that the new notes issued in exchange for the old notes pursuant to the Exchange Offer may be offered for resale, resold and otherwise transferred by holders thereof without compliance with the registration and prospectus delivery provisions of the Securities Act (other than a broker-dealer who purchased old notes exchanged for such new notes directly from the Issuer to resell pursuant to Rule 144A or any other available exemption under the Securities Act and any such holder that is an "affiliate" of the Issuer within the meaning of Rule 405 under the Securities Act), provided that such new notes are acquired in the ordinary course of such holders' business and such holders are not participating in, and have no arrangement with any other person to participate in, the distribution of such new notes.

5. By tendering old notes in the Exchange Offer, you hereby represent and warrant that:

(a) the new notes acquired pursuant to the Exchange Offer are being obtained in the ordinary course of business of you, whether or not you are the holder;

(b) you have no arrangement or understanding with any person to participate in the distribution of old notes or new notes within the meaning of the Securities Act;

(c) you are not an "affiliate," as such term is defined under Rule 405 promulgated under the Securities Act, of the Company; and

(d) if you are a broker-dealer, that you will receive the new notes for your own account in exchange for old notes that were acquired as a result of market-making activities or other trading activities and that you acknowledge that you will deliver a prospectus (or, to the extent permitted by law, make available a prospectus) in connection with any resale of such new notes.

You may, if you are unable to make all of the representations and warranties contained in Item 5 above and as otherwise permitted in the Registration Rights Agreements (as defined below), elect to have your old notes registered in the shelf registration statement described in the Registration Rights Agreement, dated as of November 17, 2009 or described by the Registration Rights Agreement, dated as of January 19, 2009 (the "Registration Rights Agreements"), by and among the Issuer, the several guarantors named therein, and the Initial Purchasers (as defined therein). Such election may be made by notifying the Issuer in writing at 1625 17th Street, Denver, Colorado 80202, Attention: Corporate Secretary. By making such election, you agree, as a holder of old notes participating in a shelf registration, to indemnify and hold harmless the Issuer, each of the directors of the Issuer, each of the officers of the Issuer who signs such shelf registration statement, each person who controls the Issuer within the meaning of either the Securities Act or the Securities Exchange Act of 1934, as amended (the "Exchange Act"), and each other holder of old notes, from and against any and all losses, claims, damages or liabilities caused by any untrue statement or alleged untrue statement of a material fact contained in any shelf registration statement or prospectus, or in any supplement thereto or amendment thereof, or caused by the omission or alleged omission to state therein a material fact required to be stated therein or necessary to make the statements therein, in the light of the circumstances under which they were made, not misleading; but only with respect to information relating to you furnished in writing by or on behalf of you expressly for use in a shelf registration statement, a prospectus or any amendments or supplements thereto. Any such indemnification shall be governed by the terms and subject to the conditions set forth in the Registration Rights Agreements, including, without limitation, the provisions regarding notice, retention of counsel, contribution and payment of expenses set forth therein. The above summary of the indemnification provision of the Registration Rights Agreements is not intended to be exhaustive and is qualified in its entirety by the Registration Rights Agreements.

6. If you are a broker-dealer that will receive new notes for your own account in exchange for old notes that were acquired as a result of market-making activities or other trading activities, you acknowledge by tendering old notes in the Exchange Offer, that you will deliver a prospectus in connection with any resale of such new notes; however, by so acknowledging and by delivering a prospectus, you will not be deemed to admit that you are an "underwriter" within the meaning of the Securities Act.

7. If you are a broker-dealer and old notes held for your own account were not acquired as a result of market-making or other trading activities, such old notes cannot be exchanged pursuant to the Exchange Offer.

8. Any of your obligations hereunder shall be binding upon your successors, assigns, executors, administrators, trustees in bankruptcy and legal and personal representatives.

INSTRUCTIONS

FORMING PART OF THE TERMS AND CONDITIONS OF THE EXCHANGE OFFER

1. Book-Entry Confirmations.

Any confirmation of a book-entry transfer to the Exchange Agent's account at DTC of old notes tendered by book-entry transfer (a "Book-Entry Confirmation"), as well as Agent's Message and any other documents required by this Letter of Transmittal, must be received by the Exchange Agent at one of its addresses set forth herein prior to 5:00 p.m., New York City time, on the Expiration Date.

2. Partial Tenders.

Tenders of old notes will be accepted only in minimum denominations of $2,000 and integral multiples of $1,000 in excess thereof. The entire principal amount of old notes delivered to the Exchange Agent will be deemed to have been tendered unless otherwise communicated to the Exchange Agent. If the entire principal amount of all old notes is not tendered, then old notes for the principal amount of old notes not tendered and new notes issued in exchange for any old notes accepted will be delivered to the holder via the facilities of DTC promptly after the old notes are accepted for exchange.

3. Validity of Tenders.

All questions as to the validity, form, eligibility (including time of receipt), acceptance, and withdrawal of tendered old notes will be determined by the Issuer, in its sole discretion, which determination will be final and binding. The Issuer reserves the absolute right to reject any or all tenders not in proper form or the acceptance for exchange of which may, in the opinion of counsel for the Issuer, be unlawful. The Issuer also reserves the absolute right to waive any of the conditions of the Exchange Offer or any defect or irregularity in the tender of any old notes. The Issuer's interpretation of the terms and conditions of the Exchange Offer (including the instructions on the Letter of Transmittal) will be final and binding on all parties. Unless waived, any defects or irregularities in connection with tenders of old notes must be cured within such time as the Issuers shall determine. Although the Issuer intends to notify holders of defects or irregularities with respect to tenders of old notes, neither the Issuer, the Exchange Agent, nor any other person shall be under any duty to give notification of any defects or irregularities in tenders or incur any liability for failure to give such notification. Tenders of old notes will not be deemed to have been made until such defects or irregularities have been cured or waived. Any old notes received by the Exchange Agent that are not properly tendered and as to which the defects or irregularities have not been cured or waived will be returned by the Exchange Agent to the tendering holders, unless otherwise provided in the Letter of Transmittal, promptly following the Expiration Date.

4. Waiver of Conditions.

The Issuer reserves the absolute right to waive, in whole or part, up to the expiration of the Exchange Offer, any of the conditions to the Exchange Offer set forth in the Prospectus or in this Letter of Transmittal.

5. No Conditional Tender.

No alternative, conditional, irregular or contingent tender of old notes will be accepted.

6. Request for Assistance or Additional Copies.

Requests for assistance or for additional copies of the Prospectus or this Letter of Transmittal may be directed to the Exchange Agent using the contact information set forth on the cover page of this Letter of Transmittal. Holders may also contact their broker, dealer, commercial bank, trust company or other nominee for assistance concerning the Exchange Offer.

7. Withdrawal.

Tenders may be withdrawn only pursuant to the limited withdrawal rights set forth in the Prospectus under the caption "Exchange Offer—Withdrawal of Tenders."

8. No Guarantee of Late Delivery.

There is no procedure for guarantee of late delivery in the Exchange Offer.

IMPORTANT: BY USING THE ATOP PROCEDURES TO TENDER OLD NOTES, YOU WILL NOT BE REQUIRED TO DELIVER THIS LETTER OF TRANSMITTAL TO THE EXCHANGE AGENT. HOWEVER, YOU WILL BE BOUND BY ITS TERMS, AND YOU WILL BE DEEMED TO HAVE MADE THE ACKNOWLEDGMENTS AND THE REPRESENTATIONS AND WARRANTIES IT CONTAINS, JUST AS IF YOU HAD SIGNED IT.

ANNEX B: GLOSSARY OF NATURAL GAS AND OIL TERMS

The terms defined in this section are used throughout this prospectus:

"3D." Method for collecting, processing, and interpreting seismic data in three dimensions.

"AMI." Area of mutual interest.

"Bbl." One stock tank barrel, of 42 U.S. gallons liquid volume, used herein in reference to crude oil, condensate or natural gas liquids.

"Bcf." One billion cubic feet of natural gas.

"Bcfe." One billion cubic feet of natural gas equivalent with one barrel of oil converted to six thousand cubic feet of natural gas.

"Basin." A large natural depression on the earth's surface in which sediments generally brought by water accumulate.

"Completion." The process of treating a drilled well followed by the installation of permanent equipment for the production of natural gas or oil, or in the case of a dry hole, the reporting of abandonment to the appropriate agency.

"DD&A." Depreciation, depletion, amortization and accretion.

"Delineation." The process of placing a number of wells in various parts of a reservoir to determine its boundaries and production characteristics.

"Developed acreage." The number of acres that are allocated or assignable to productive wells or wells capable of production.

"Development well." A well drilled within the proved area of an oil or natural gas reservoir to the depth of a stratigraphic horizon known to be productive.

"Drill-to-earn." The process of earning an interest in leasehold acreage by drilling a well pursuant to a farm-in, exploration, or other agreement.

"Dry hole." A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.

"Enhanced recovery." The recovery of natural gas and oil through the injection of liquids or gases into the reservoir, supplementing its natural energy. Enhanced recovery methods are often applied when production slows due to depletion of the natural pressure.

"Exploratory well." A well drilled to find and produce natural gas or oil reserves not classified as proved, to find a new reservoir in a field previously found to be productive of natural gas or oil in another reservoir or to extend a known reservoir.

"Farm-in or farm-out." An agreement under which the owner of a working interest in a natural gas and oil lease assigns the working interest or a portion of the working interest to another party who desires to drill on the leased acreage. Generally, the assignee is required to drill one or more wells in order to earn its interest in the acreage. The assignor usually retains a royalty or reversionary interest in the lease. The interest received by an assignee is a "farm-in" while the interest transferred by the assignor is a "farm-out."

"Field." An area consisting of a single reservoir or multiple reservoirs all grouped on, or related to, the same individual geological structural feature or stratigraphic condition. The field name refers to the surface area, although it may refer to both the surface and the underground productive formations.

"Formation." A layer of rock which has distinct characteristics that differs from nearby rock.

"Gross acres or gross wells." The total acres or wells, as the case may be, in which a working interest is owned.

"Horizontal drilling." A drilling technique used in certain formations where a well is drilled vertically to a certain depth and then drilled at a right angle within a specified interval.

"Infill wells." Wells drilled into the same pool as known producing wells so that oil or natural gas does not have to travel as far through the formation.

"MBbl." One thousand barrels of crude oil, condensate or natural gas liquids.

"Mcf." One thousand cubic feet of natural gas.

"MMBtu." One million British thermal units.

"MMcf." One million cubic feet of natural gas.

"MMcfe." Million cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids.

"MMcfe/d." MMcfe per day.

"NGLs." Natural gas liquids. Hydrocarbons found in natural gas which may be extracted as liquefied petroleum gas and natural gasoline.

"NYMEX." The New York Mercantile Exchange.

"Net acres." The percentage of total acres an owner has out of a particular number of acres, or a specified tract. An owner who has 50% interest in 100 acres owns 50 net acres.

"Potential drilling locations." Total gross resource play locations that we may be able to drill on our existing acreage. Our actual drilling activities may change depending on the availability of capital, regulatory approvals, seasonal restrictions, natural gas and oil prices, costs, drilling results and other factors.

"Productive well." A well that is found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of the production exceed production expenses and taxes.

"Prospect." A specific geographic area which, based on supporting geological, geophysical or other data and also preliminary economic analysis using reasonably anticipated prices and costs, is deemed to have potential for the discovery of commercial hydrocarbons.

"Proved developed reserves." Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

"Proved reserves." The estimated quantities of oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be commercially recoverable in future years from known reservoirs under existing economic and operating conditions.

"Proved undeveloped reserves ("PUD")." Proved reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion.

"PV-10." When used with respect to natural gas and oil reserves, PV-10 means the estimated future gross revenue to be generated from the production of proved reserves, net of estimated production and future development and abandonment costs, using prices and costs in effect at the determination date, before income taxes, and without giving effect to non-property-related expenses, discounted to a present value using an annual discount rate of 10% in accordance with the guidelines of the SEC. PV-10 is not a financial measure calculated in accordance with generally accepted accounting principles ("GAAP") and generally differs from Standardized Measure, the most directly comparable GAAP financial measure, because it does not include the effects of income taxes on future net revenues. Neither PV-10 nor Standardized Measure represents an estimate of the fair market value of our natural gas and oil properties. We and others in the industry use PV-10 as a measure to compare the relative size and value of proved reserves held by companies without regard to the specific tax characteristics of such entities.

"Recompletion." The process of re-entering an existing wellbore that is either producing or not producing and completing new reservoirs in an attempt to establish or increase existing production.

"Reservoir." A porous and permeable underground formation containing a natural accumulation of producible oil and/or natural gas that is confined by impermeable rock or water barriers and is separate from other reservoirs.

"Simul-frac." Simultaneously fracture treating two or more wells within the same fracture plane in order to create pressure interference between the wells and thereby increasing the stimulated reservoir volume.

"Spacing." The distance between wells producing from the same reservoir. Spacing is often expressed in terms of acres, e.g., 40-acre spacing, and is often established by regulatory agencies.

"Standardized measure." Discounted future net cash flows estimated by applying year-end prices to the estimated future production of year-end proved reserves. Future cash inflows are reduced by estimated future production and development costs based on period-end costs to determine pre-tax cash inflows. Future income taxes, if applicable, are computed by applying the statutory tax rate to the excess of pre-tax cash inflows over our tax basis in the natural gas and oil properties. Future net cash inflows after income taxes are discounted using a 10% annual discount rate.

"Undeveloped acreage." Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of natural gas and oil regardless of whether such acreage contains proved reserves.

"Unit." The joining of all or substantially all interests in a reservoir or field, rather than a single tract, to provide for development and operation without regard to separate property interests. Also, the area covered by a unitization agreement.

"Waterflood." The injection of water into an oil reservoir to "push" additional oil out of the reservoir rock and into the wellbores of producing wells. Typically an enhanced recovery process.

"Wellbore." The hole drilled by the bit that is equipped for natural gas production on a completed well. Also called well or borehole.

"Working interest." The right granted to the lessee of a property to explore for and to produce and own natural gas or other minerals. The working interest owners bear the exploration, development, and operating costs on either a cash, penalty, or carried basis.

INDEX TO FINANCIAL STATEMENTS

ANTERO RESOURCES LLC

Consolidated Balance Sheets

December 31, 2009 and March 31, 2010

(In thousands)

(Unaudited)

	December 31, 2009	March 31, 2010
Assets		
Current assets:		
Cash and cash equivalents	$ 10,669	6,314
Accounts receivable—trade, net of allowance for doubtful accounts of $424 at December 31, 2009 and March 31, 2010	35,897	32,433
Accrued revenue	17,459	22,587
Prepaid expenses	7,419	7,386
Derivative instruments	22,105	62,245
Inventories	1,295	1,292
Total current assets	94,844	132,257
Property and equipment:		
Natural gas properties, at cost (successful efforts method):		
Unproved properties	596,694	600,233
Producing properties	1,340,827	1,407,126
Gathering systems and facilities	185,688	188,506
Other property and equipment	3,302	3,474
	2,126,511	2,199,339
Less accumulated depletion, depreciation, and amortization	(322,992)	(355,995)
Property and equipment, net	1,803,519	1,843,344
Derivative instruments	18,989	77,661
Other assets, net	19,214	22,636
Total assets	$ 1,936,566	2,075,898

See accompanying notes to consolidated financial statements.

ANTERO RESOURCES LLC

Consolidated Balance Sheets (Continued)

December 31, 2009 and March 31, 2010

(In thousands)

(Unaudited)

	December 31, 2009	March 31, 2010
Liabilities and Equity		
Current liabilities:		
Accounts payable	$ 48,594	59,027
Accrued expenses	24,440	37,601
Revenue distributions payable	29,304	32,225
Advances from joint interest owners	1,400	1,631
Derivative instruments	8,623	7,994
Capital leases—current	132	134
Total current liabilities	112,493	138,612
Long-term liabilities:		
Bank credit facility	142,080	—
Senior notes	372,397	528,316
Derivative instruments	2,464	1,568
Asset retirement obligations	3,487	3,627
Deferred tax payable	424	11,742
Capital leases—noncurrent	1,022	988
Other long term liabilities	3,092	3,092
Total liabilities	637,459	687,945
Equity:		
Members' equity	1,392,833	1,392,833
Accumulated deficit	(123,447)	(35,842)
	1,269,386	1,356,991
Noncontrolling interest in consolidated subsidiary	29,721	30,962
Total equity	1,299,107	1,387,953
Total liabilities and equity	$ 1,936,566	2,075,898

See accompanying notes to consolidated financial statements.

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ANTERO RESOURCES LLC

Consolidated Statements of Operations

Three months ended March 31, 2009 and 2010

(In thousands)

(Unaudited)

	2009	2010
Revenue:		
Natural gas sales	$ 37,332	53,952
Net realized and unrealized gains on commodity derivative instruments including unrealized gains of $5,114 and $98,812, respectively	38,686	111,083
Oil sales	1,063	2,114
Gathering and processing revenue	4,379	6,413
Total revenue	81,460	173,562
Operating expenses:		
Lease operating expenses	6,945	4,598
Gathering, compression and transportation	6,375	10,141
Production taxes	1,832	2,670
Exploration expenses	2,429	1,352
Impairment of unproved properties	7,767	2,262
Depletion, depreciation and amortization	39,701	32,996
Accretion of asset retirement obligations	62	73
General and administrative	4,406	4,412
Total operating expenses	69,517	58,504
Operating income	11,943	115,058
Other income (expense):		
Interest expense, net	(7,178)	(13,292)
Net realized and unrealized losses on interest rate derivative instruments including unrealized gains of $697 and $1,525, respectively	(1,375)	(1,602)
Total other expense	(8,553)	(14,894)
Income before income taxes	3,390	100,164
Deferred income tax benefit (expense)	1,605	(11,318)
Net income	4,995	88,846
Noncontrolling interest in net loss (income) of consolidated subsidiary	159	(1,241)
Net income attributable to Antero stockholders	$ 5,154	87,605

See accompanying notes to consolidated financial statements.

ANTERO RESOURCES LLC

Consolidated Statements of Cash Flows

Three months ended March 31, 2009 and 2010

(In thousands)

(Unaudited)

	2009	2010
Cash flows from operating activities:		
Net income	$ 4,995	88,846
Adjustment to reconcile net loss to net cash provided by operating activities:		
Depletion, depreciation, and amortization	39,701	32,996
Dry hole costs	759	374
Impairment of unproved properties	7,767	2,262
Accretion of asset retirement obligations	62	73
Amortization of bond premium		(81)
Amortization of deferred financing costs	643	1,005
Stock compensation	176	—
Unrealized losses (gains) on derivative instruments, net	(5,812)	(100,337)
Deferred tax expense (benefit)	(1,605)	11,318
Changes in current assets and liabilities:		
Accounts receivable	15,721	3,464
Accrued revenue	6,829	(5,128)
Prepaid expenses	565	33
Inventories	56	3
Accounts payable	(10,259)	848
Accrued expenses	1,354	13,161
Revenue distributions payable	7,286	2,921
Advances from joint interest owners	(1,598)	231
Net cash provided by operating activities	66,640	51,989
Cash flows from investing activities:		
Additions to unproved properties	(4,977)	(5,801)
Additions to proved properties	(367)	—
Drilling costs	(108,784)	(57,023)
Gathering systems and facilities	(1,626)	(2,809)
Additions to other property and equipment	(40)	(172)
Decrease (increase) in other assets	473	(184)
Net cash used in investing activities	(115,321)	(65,989)
Cash flows from financing activities:		
Issuance of senior notes	$ —	156,000
Payments on bank credit facility	(90,000)	(142,080)
Payments on capital lease obligations	(30)	(32)
Financing costs	(6,391)	(4,243)
Issuance of preferred stock	105,000	—
Other	(41)	—
Net cash received from noncontrolling interest	1,174	—
Net cash provided by financing activities	9,712	9,645
Net decrease in cash and cash equivalents	(38,969)	(4,355)
Cash and cash equivalents, beginning of period	38,969	10,669
Cash and cash equivalents, end of period	$ —	6,314
Supplemental disclosure of cash flow information:		
Cash paid during the period for interest	$ (5,648)	(4,306)
Supplemental disclosure of noncash investing activities:		
Net changes in accounts payable for additions to properties, systems and facilities	$ (50,900)	9,585

See accompanying notes to consolidated financial statements.

ANTERO RESOURCES LLC

Notes to Consolidated Financial Statements

March 31, 2010 and December 31, 2009

(Unaudited)

(1) Organization

(a) Business and Organization

Antero Resources LLC, a limited liability company, and its consolidated subsidiaries (collectively referred to as the Company, we, or our) are engaged in the exploration for and the production of natural gas and oil onshore in the United States in unconventional reservoirs, which can generally be characterized as fractured shales and tight sand formations. Our properties are primarily located in the Appalachian Basin in West Virginia and Pennsylvania, the Arkoma Basin in Oklahoma and the Piceance Basin in Colorado. We also have certain midstream gathering and pipeline operations which are ancillary to our interests in producing properties in these basins. Our corporate headquarters are in Denver, Colorado.

Our consolidated financial statements as of March 31, 2010 and December 31, 2009 include the accounts of Antero Resources LLC, and its directly and indirectly owned subsidiaries. The subsidiaries include Antero Resources Corporation (Antero Arkoma), Antero Resources Piceance Corporation (Antero Piceance), Antero Resources Midstream Corporation (Antero Midstream), Antero Resources Pipeline Corporation (Antero Pipeline), Antero Resources Appalachian Corporation (Antero Appalachian), and Antero Resources Finance Corporation (Antero Finance) (collectively referred to as the Antero Entities). The consolidated financial statements for the three months ended March 31, 2009 and 2010 include the accounts of the Antero Entities. For periods prior to October 2009, ownership of the entities was under common control; the outstanding equity instruments of these entities were held by the same individuals or entities in the same percentage. In October 2009, the equity structure was reorganized in a nontaxable transaction by the formation of Antero Resources LLC, which issued units of members' equity to the stockholders of the operating entities in exchange for all of their preferred and common shares in each entity. The assets and liabilities of each of the entities are included in the consolidated financial statements at their historical basis.

(b) Centrahoma Processing Joint Venture

Antero Midstream has a 60% interest in Centrahoma Processing LLC, a joint venture formed along with MarkWest Oklahoma Gas Company, LLC (MarkWest) to process gas from the Arkoma Basin. The joint venture is accounted for as a consolidated subsidiary with MarkWest's 40% interest accounted for as a noncontrolling interest in the financial statements.

(2) Basis of Presentation and Significant Accounting Policies

(a) Basis of Presentation

The accompanying unaudited consolidated financial statements as of December 31, 2009 and March 31, 2010 include the accounts of Antero Resources LLC and its subsidiaries. The March 31, 2009 consolidated financial statements are presented on a basis that is consistent with those for the three-month period ended March 31, 2010. All significant intercompany accounts and transactions have been eliminated.

These financial statements have been prepared pursuant to the rules and regulations of the Securities and Exchange Commission (SEC) applicable to interim financial information and should be

ANTERO RESOURCES LLC

Notes to Consolidated Financial Statements (Continued)

March 31, 2010 and December 31, 2009

(Unaudited)

(2) Basis of Presentation and Significant Accounting Policies (Continued)

read in the context of the December 31, 2009 consolidated financial statements and notes thereto for a more complete understanding of the Company's operations, financial position and accounting policies. The December 31, 2009 financial statements have been filed with the SEC in the Company's Registration Statement on Form S-4.

The accompanying unaudited consolidated financial statements of the Company have been prepared in accordance with accounting principles generally accepted in the United States (GAAP) for interim financial information and, accordingly, do not include all of the information and footnotes required by GAAP for complete financial statements. In the opinion of management, the accompanying unaudited consolidated financial statements include all adjustments (consisting of normal and recurring accruals) considered necessary to present fairly the Company's financial position as of March 31, 2010, results of their operations and their cash flows for the three months ended March 31, 2009 and 2010. Operating results for the three months ended March 31, 2010 are not necessarily indicative of the results that may be expected for the full year because of the impact of fluctuations in prices received for natural gas and oil, natural production declines, the uncertainty of exploration and development drilling results and other factors.

As of May 14, 2010, which is the date these financial statements were issued, the Company completed its evaluation of potential subsequent events for disclosure and no items requiring disclosure were identified.

The Company's exploration and production activities are accounted for under the successful efforts method.

(b) Use of Estimates

The preparation of financial statements in conformity with generally accepted accounting principles in the United States requires management to make estimates and assumptions that affect the reported assets and liabilities and disclosure of contingent assets and liabilities at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the reporting period. Changes in facts and circumstances or discovery of new information may result in revised estimates, and actual results could differ from those estimates. The Company's financial statements are based on a number of significant judgments, assumptions, and estimates including estimates of gas and oil reserve quantities, which are the basis for the calculation of depreciation, depletion amortization, present value of future reserves, and impairment of oil and gas properties. Reserve estimates are by their nature inherently imprecise.

(c) Risks and Uncertainties

Historically, the market for natural gas has experienced significant price fluctuations. Prices for natural gas have been particularly volatile in recent years. The price fluctuations can result from variations in weather, levels of production in the region, availability of transportation capacity to other regions of the country, and various other factors. Increases or decreases in prices received could have a significant impact on the Company's future results of operations.

ANTERO RESOURCES LLC

Notes to Consolidated Financial Statements (Continued)

March 31, 2010 and December 31, 2009

(Unaudited)

(2) Basis of Presentation and Significant Accounting Policies (Continued)

(d) Derivative Financial Instruments

In order to manage its exposure to oil and gas price volatility, the Company enters into derivative transactions from time to time, including commodity swap agreements, collar agreements, and other similar agreements relating to natural gas expected to be produced. From time to time, the Company also enters into derivative contracts to mitigate the effects of interest rate fluctuations. To the extent legal right of offset with a counterparty exists, the Company reports derivative assets and liabilities on a net basis. The Company has exposure to credit risk to the extent the counterparty is unable to satisfy its settlement obligation. The Company actively monitors the credit worthiness of each counterparty and assesses the impact, if any, on its derivative position.

The Company records derivative instruments on the balance sheet as either an asset or liability measured at fair value and records changes in the fair value of derivatives in current earnings as they occur. Changes in the fair value of commodity derivatives are classified as revenues, and changes in the fair value of interest rate derivatives are classified as other income (expense).

(e) Fair Value Measurements

Authoritative accounting guidance defines fair value, establishes a framework for measuring fair value, and requires disclosures about fair value measurements. This guidance also relates to all nonfinancial assets and liabilities that are not recognized or disclosed on a recurring basis (e.g., those measured at fair value in a business combination, the initial recognition of asset retirement obligations, and impairments of proved oil and gas properties, and other long-lived assets). The fair value is the price that the Company estimates would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. A fair value hierarchy is used to prioritize input to valuation techniques used to estimate fair value. An asset or liability subject to the fair value requirements is categorized within the hierarchy based on the lowest level of input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input to the fair value measurement in its entirety requires judgment and considers factors specific to the asset or liability. The highest priority (Level 1) is given to unadjusted quoted market prices in active markets for identical assets or liabilities, and the lowest priority (Level 3) is given to unobservable inputs. Level 2 inputs are data, other than quoted prices included within Level 1, that are observable for the asset or liability, either directly or indirectly. Instruments which are valued using Level 2 inputs include nonexchange traded derivatives such as over-the-counter commodity price swaps, basis swaps, and interest rate swaps. Valuation models used to measure fair value of these instruments consider various Level 2 inputs including (i) quoted forward prices for commodities, (ii) time value, (iii) quoted forward interest rates, (iv) current market prices and contractual prices for the underlying instruments, (v) risk of nonperformance by the Company and the counterparty, (vi) and other relevant economic measures. The Company utilizes its counterparties to assess the reasonableness of its prices and valuation techniques. To the extent a legal right of offset with a counterparty exists, the derivative assets and liabilities are reported on a net basis.

ANTERO RESOURCES LLC

Notes to Consolidated Financial Statements (Continued)

March 31, 2010 and December 31, 2009

(Unaudited)

(2) Basis of Presentation and Significant Accounting Policies (Continued)

(f) Income Taxes

Antero Resources LLC and each of its subsidiaries file separate federal and state income tax returns. Antero Resources LLC is a partnership for income tax purposes and therefore is not subject to federal or state income taxes. The tax on the income of Antero Resources LLC is borne by the individual members through the allocation of taxable income.

The Company and its subsidiaries have combined net operating loss carryforwards as of December 31, 2009 of approximately $276 million. The Company's deferred tax assets relate primarily to net operating loss carryforwards and its deferred tax liabilities relate primarily to oil and gas properties and unrealized gains on derivative instruments. In assessing the realizability of deferred tax assets, management considers whether some portion or all of the deferred tax assets will be realized based on a more likely than not standard of judgment. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during the periods in which those temporary differences become deductible. Management considers the scheduled reversal of deferred tax liabilities, projected future taxable income, and tax planning strategies in making this assessment. Due to the lack of historical profitable operations and based upon the projections for future taxable income over the periods in which the deferred tax assets are deductible, management believes that the Company will not realize the benefits of all of these deductible differences and has recorded valuation allowances in those subsidiaries having net deferred tax assets to the extent deferred tax assets exceed their deferred tax liabilities. The amount of deferred tax assets considered realizable could be reduced in the near term if estimates of future taxable income during the carryforward period are reduced. The Company's income tax expense (benefit) differs from the amount that would be computed by applying the U.S. statutory federal income tax rate of 34% to consolidated income for the three months ended March 31, 2009 and 2010 primarily because of changes in the valuation allowance.

(g) Industry Segment and Geographic Information

We have evaluated how the Company is organized and managed and have identified one operating segment—the exploration and production of oil, natural gas, and natural gas liquids. We consider our gathering, processing and marketing functions as ancillary to our oil and gas producing activities. All of our assets are located in the United States and all of our revenues are attributable to United States customers.

(3) Credit Facilities

(a) Bank Credit Facility

The Company has entered into a credit agreement (Credit Facility), which provides for loans up to $400 million. The borrowings under the Credit Facility are subject to borrowing base limitations based on the collateral value of our proved reserves and are subject to regular semiannual redeterminations. The next semiannual redetermination of our borrowing base is scheduled to occur in October 2010. The borrowing base at March 31, 2010 was $369 million. In May 2010, the borrowing base was increased to $400 million as a result of the most recent redetermination.

ANTERO RESOURCES LLC

Notes to Consolidated Financial Statements (Continued)

March 31, 2010 and December 31, 2009

(Unaudited)

(3) Credit Facilities (Continued)

The Credit Facility is secured by mortgages on substantially all of the Company's properties and guarantees from the Company's operating subsidiaries. All advances are due and payable on March 15, 2012. The Credit Facility contains certain covenants, including restrictions on indebtedness and dividends, and requirements with respect to working capital and leverage ratios. Interest is payable at a variable rate based on LIBOR or the prime rate based on the Company's election at the time of borrowing. The Company is in compliance with its financial debt covenants as of March 31, 2010.

As of March 31, 2010, the Company had no outstanding borrowings under the Credit Facility. The Company pays commitment fees of up to 0.50% of the unused borrowing base. The Company had approximately $11.4 million in outstanding letters of credit under the facility at March 31, 2010. Outstanding borrowings at December 31, 2009 were $142.1 million and $3.0 million of letters of credit.

(b) Senior Notes

On November 17, 2009, a newly formed wholly owned subsidiary of Antero Resources LLC, Antero Finance, issued $375 million of 9.375% senior notes due December 1, 2017 at a discount of $2.6 million. In January 2010, an additional $150 million of the same series of 9.375% senior notes were issued at a premium of $6 million. The notes are unsecured and subordinate to the Company's bank credit facility to the extent of the value of the collateral securing the bank credit facility. The notes are guaranteed on a senior unsecured basis by Antero Resources LLC, all of its wholly owned subsidiaries (other than Antero Finance), and certain of its future restricted subsidiaries. Interest on the notes is payable on June 1 and December 1 of each year, commencing on June 1, 2010. Antero Finance may redeem all or part of the notes at any time on or after December 1, 2013 at redemption prices from 104.688% on or after December 1, 2013 to 100.00% on or after December 1, 2015. In addition, on or before December 1, 2012, Antero Finance may redeem up to 35% of the aggregate principal amount of the notes with the net cash proceeds of certain equity offerings, if certain conditions are met, at a redemption price of 109.375%. At any time prior to December 1, 2013, Antero Finance may also redeem the notes, in whole or in part, at a price equal to 100% of the principal amount of the notes plus a "make-whole" premium. If Antero Resources LLC undergoes a change of control, Antero Finance may be required to offer to purchase notes from the holders.

(4) Ownership Structure

At December 31, 2009 and March 31, 2010, the outstanding units in Antero Resources LLC are summarized as follows:

	Units authorized and issued
Class I units	103,466,666
Class A and B units	36,193,071
Class A and B profits units	19,726,873
	159,386,610

At March 31, 2010, 202,261 units are outstanding and not vested under the terms of the preferred and common stock awards in the Antero Entities for which they were exchanged.

ANTERO RESOURCES LLC

Notes to Consolidated Financial Statements (Continued)

March 31, 2010 and December 31, 2009

(Unaudited)

(4) Ownership Structure (Continued)

None of the three classes of outstanding units are entitled to current cash distributions or are convertible into indebtedness. The Company has no obligation to repurchase these units at the election of the unitholders.

In the event of a distribution from Antero Resources LLC, amounts available for distribution are distributed according to a formula set forth in the LLC agreement that takes into account the relative priority of the various classes of units outstanding. In the event of a distribution due to the disposition of an individual Antero Entity, a portion of the proceeds is allocated to the employees of the Company based on a requisite return financial threshold. In general, distributions are made first to holders of the Class I units until they have received their investment amount and an 8% special allocation and then, as a group, to the holders of all classes of units together. The Class I units participate on a pro rata basis with the other classes of units in funds available for distributions in excess of the Class I unit investment and special allocation amounts.

At December 31, 2009 and March 31, 2010, the Class I units have an aggregate liquidation priority, including the special allocation of 8% per annum, of $1.63 billion and $1.66 billion, respectively.

During the three months ended March 31, 2009, the Company issued $105 million of Series B preferred stock.

(5) Financial Instruments

The carrying values of trade receivables, trade payables, the credit facility, and the term loan at December 31, 2009 and March 31, 2010 approximated market value. The carrying value of the bank credit facility at December 31, 2009 and March 31, 2010 approximated fair value because the variable interest rates are reflective of current market conditions.

Based on Level 2 market data, the fair value of the Company's senior notes was approximately $382.5 million and $541.0 million at December 31, 2009 and March 31, 2010, respectively.

(6) Asset Retirement Obligations

The following is a reconciliation of our asset retirement obligations for the three months ended March 31, 2010 (in thousands):

Asset retirement obligations—beginning of period	$ 3,487
Obligations incurred	67
Accretion expense	73
Asset retirement obligations—end of period	$ 3,627

ANTERO RESOURCES LLC

Notes to Consolidated Financial Statements (Continued)

March 31, 2010 and December 31, 2009

(Unaudited)

(7) Derivative Instruments and Risk Management Activities

(a) Commodity Derivatives

The Company periodically enters into natural gas derivative contracts with counterparties to hedge the price risk associated with a portion of its production. These derivatives are not held for trading purposes. To the extent that changes occur in the market prices of natural gas, the Company is exposed to market risk on these open contracts. This market risk exposure is generally offset by the change in market prices of natural gas recognized upon the ultimate sale of the natural gas produced.

For the three months ended March 31, 2009 and 2010, the Company was party to natural gas fixed price swaps. When actual commodity prices exceed the fixed price provided by the swap contracts, the Company pays the excess to the counterparty, and when actual commodity prices are below the contractually provided fixed price receives the difference from the counterparty. The Company's natural gas swaps have not been designated as hedges for accounting purposes; therefore, all gains and losses were recognized in income currently.

As of March 31, 2010, derivative positions with JP Morgan, BNP Paribas, Wells Fargo, KeyBank, Union Bank, and Barclays accounted for approximately 54%, 22%, 10%, 8%, 4%, and 2%, respectively, of the net fair value of our commodity derivative assets position. The Company has no collateral from any counterparties. Commodity and interest rate derivative positions are with institutions who have a position in our Credit Facility and are secured by the collateral pledged on the Credit Facility and cross default provisions between the Credit Facility and the derivative instruments. There are no past due receivables from or payables to any of our counterparties.

Through March 31, 2010, and including swaps entered into since March 31, 2010 through May 14, 2010, the Company has entered into fixed price natural gas swaps in order to hedge a portion of its natural gas production from April 1, 2010 through December 31, 2014 as summarized in the following table. Hedge agreements referenced to the Centerpoint, NYMEX, and Transco Zone 4 indices are for production in the Arkoma Basin. Hedge agreements referenced to the CIG index are for production in

ANTERO RESOURCES LLC

Notes to Consolidated Financial Statements (Continued)

March 31, 2010 and December 31, 2009

(Unaudited)

(7) Derivative Instruments and Risk Management Activities (Continued)

the Piceance Basin. Hedge agreements referenced to the CGTAP index are for production from the Appalachian Basin.

	MMbtu/day	Weighted average index price
Nine months ending December 31, 2010:		
Centerpoint	30,000	$ 7.20
CIG	30,000	5.12
NYMEX	10,000	6.21
CGTAP	20,000	5.98
Year ending December 31, 2011:		
CIG	35,000	$ 5.78
Transco zone 4	35,000	6.91
CGTAP	30,000	6.60
Year ending December 31, 2012:		
CIG	35,000	$ 6.06
Transco zone 4	35,000	7.05
CGTAP	30,000	6.66
Year ending December 31, 2013:		
CIG	40,000	$ 5.93
Transco zone 4	40,000	6.51
CGTAP	30,000	6.64
Year ending December 31, 2014:		
CIG	40,000	$ 6.07
Transco zone 4	20,000	6.51
CGTAP	50,000	6.54
Centerpoint	10,000	6.20

(b) Interest Rate Derivatives

The Company has entered into various floating-to-fixed interest rate swap derivative contracts to manage exposures to changes in interest rates from variable rate obligations under the second lien term loan and the bank credit facility. Under the swaps, the Company makes payments to the swap counterparty when the variable LIBOR three-month rate falls below the fixed rate or receives payments from the swap counterparty when the variable LIBOR three-month rate goes above the fixed rate. The

ANTERO RESOURCES LLC

Notes to Consolidated Financial Statements (Continued)

March 31, 2010 and December 31, 2009

(Unaudited)

(7) Derivative Instruments and Risk Management Activities (Continued)

outstanding swap agreements during the three months ended March 31, 2009 and 2010 are summarized as follows:

Notional amount of swap	Covering periods	Fixed rate
$225 million	May 2007 to July 1, 2011	4.11%
$150 million	April 1, 2008 to April 1, 2010	2.8025%
$51 million	December 10, 2008 to December 10, 2009	2.79%

When the Company retired the floating rate second lien term loan of $225 million out of the proceeds from the rate 9.375% senior notes in November 2009, it did not terminate the $225 million floating-to-fixed rate swap associated with this debt; therefore, this swap does not have debt associated with it.

The Company had a notional amount of $150.0 million of interest rate swaps outstanding related to its credit facility at December 31, 2009 and March 31, 2010, which had $142.1 million and $-0- outstanding, respectively. These swaps expired on April 1, 2010.

(c) Summary

The following is a summary of the fair values of derivative instruments not designated as hedges for accounting purposes and where such values are recorded in the consolidated balance sheets as of December 31, 2009 and March 31, 2010. None of the Company's derivative instruments are designated as hedges for accounting purposes.

	2009		2010	
	Balance sheet location	Fair value (In thousands)	Balance sheet location	Fair value (In thousands)
Asset derivatives not designated as hedges for accounting purposes:				
Commodity contracts	Current assets	$ 22,105	Current assets	$ 62,245
Commodity contracts	Long-term assets	18,989	Long-term assets	77,661
Total asset derivatives		$ 41,094		$ 139,906
Liability derivatives not designated as hedges for accounting purposes:				
Interest rate contracts	Current liabilities	$ 8,623	Current liabilities	$ 7,994
Interest rate contracts	Long-term liabilities	2,464	Long-term liabilities	1,568
Total liability derivatives		$ 11,087		$ 9,562

ANTERO RESOURCES LLC

Notes to Consolidated Financial Statements (Continued)

March 31, 2010 and December 31, 2009

(Unaudited)

(7) Derivative Instruments and Risk Management Activities (Continued)

The following is a summary of realized and unrealized gains (losses) on derivative instruments and where such values are recorded in the consolidated statements of operations for the three months ended March 31, 2009 and 2010:

	Statement of operations location	2009	2010
Realized gains on commodity contracts	Revenue	$ 33,572	12,271
Unrealized gains (losses) on commodity contracts	Revenue	5,114	98,812
Total gains on commodity contracts		38,686	111,083
Realized gains (losses) on interest rate contracts	Other income (expense)	(2,072)	(3,127)
Unrealized gains (losses) on interest rate contracts	Other income (expense)	697	1,525
Total losses on rate contracts		(1,375)	(1,602)
Net gains on derivative contracts		$ 37,311	109,481

The following table summarizes the valuation of investments and financial instruments by the fair value hierarchy described in note 1 at March 31, 2010:

Description	Fair value measurements using Quoted prices in active markets for identical assets (Level 1)	Significant other observable inputs (Level 2)	Significant unobservable inputs (Level 3)	Total
	(In thousands)			
Derivatives asset (liability):				
Fixed price commodity swaps	$ —	139,906	—	139,906
Interest rate swaps	—	(9,562)	—	(9,562)
	$ —	130,344	—	130,344

(8) Contingencies

Litigation

The Company is party to various legal proceedings and claims in the ordinary course of its business. The Company believes certain of these matters will be covered by insurance and that the outcome of other matters will not have a material adverse effect on its consolidated financial position, results of operations, or liquidity.

ANTERO RESOURCES LLC

Notes to Consolidated Financial Statements (Continued)

March 31, 2010 and December 31, 2009

(Unaudited)

(9) Guarantor Subsidiaries

The following entities are guarantors of the Company's senior notes: Antero Resources LLC (the Parent Company), Antero Arkoma, Antero Piceance, Antero Midstream, Antero Pipeline, and Antero Appalachian (collectively, the Guarantor Companies). Each of the guarantees is full and unconditional and joint and several. The nonguarantor company is Centrahoma Processing LLC.

The condensed consolidating financial statements below present the financial position, results of operations, and cash flows of Antero Resources LLC, its combined guarantor subsidiaries, and the nonguarantor company.

Condensed Consolidating Balance Sheet
December 31, 2009

	Parent company	Guarantor companies	Nonguarantor company (In thousands)	Eliminations	Total
Assets					
Cash and cash equivalents	$ —	9,090	1,579	—	10,669
Accounts receivable	—	23,795	12,102	—	35,897
Derivative instruments	—	22,105	—	—	22,105
Other current assets	—	35,218	599	(9,644)	26,173
Total current assets	—	90,208	14,280	(9,644)	94,844
Property and equipment—net	—	1,734,138	69,381	—	1,803,519
Derivative instruments	—	18,989	—	—	18,989
Other assets, net	—	17,673	1,541	—	19,214
Investment in subsidiaries	1,299,107	—	—	(1,299,107)	—
Total assets	$ 1,299,107	1,861,008	85,202	(1,308,751)	1,936,566
Liabilities and Equity					
Accounts payable and accrued expenses	$ —	72,168	866	—	73,034
Revenue distribution payable and advances from joint interest owners	—	30,704	—	—	30,704
Derivative instruments	—	8,623	—	—	8,623
Other current liabilities	—	(1,283)	11,059	(9,644)	132
Total current liabilities	—	110,212	11,925	(9,644)	112,493
Long-term liabilities:					
Bank credit facility and senior notes	—	514,477	—	—	514,477
Derivative instruments	—	2,464	—	—	2,464
Other long term liabilities	—	8,025	—	—	8,025
Total liabilities	—	635,178	11,925	(9,644)	637,459
Total equity	1,299,107	1,225,830	73,277	(1,299,107)	1,299,107
Total liabilities and equity	$ 1,299,107	1,861,008	85,202	(1,308,751)	1,936,566

ANTERO RESOURCES LLC

Notes to Consolidated Financial Statements (Continued)

March 31, 2010 and December 31, 2009

(Unaudited)

(9) Guarantor Subsidiaries (Continued)

Condensed Consolidating Balance Sheet
March 31, 2010

	Parent Company	Guarantor companies	Nonguarantor company	Eliminations	Total
			(In thousands)		
Assets					
Cash and cash equivalents	$ —	3,738	2,576	—	6,314
Accounts receivable	—	42,803	12,217	—	55,020
Derivative instruments	—	62,245	—	—	62,245
Other current assets	—	58,863	143	(50,328)	8,678
Total current assets	—	167,649	14,936	(50,328)	132,257
Property and equipment—net	—	1,774,699	68,645	—	1,843,344
Derivative instruments	—	77,661	—	—	77,661
Other assets, net	—	21,096	1,540	—	22,636
Investment in subsidiaries	1,387,953	—	—	(1,387,953)	—
Total assets	$ 1,387,953	2,041,105	85,121	(1,438,281)	2,075,898
Liabilities and Equity					
Accounts payable and accrued expenses	$ —	95,823	805	—	96,628
Revenue distribution payable and advances from joint interest owners	—	23,277	10,579	—	33,856
Derivative instruments	—	7,994	—	—	7,994
Other current liabilities	—	50,462	—	(50,328)	134
Total current liabilities	—	177,556	11,384	(50,328)	138,612
Long-term liabilities:					
Bank credit facility and term notes	—	528,316	—	—	528,316
Derivative instruments	—	1,568	—	—	1,568
Other long term liabilities	—	19,449	—	—	19,449
Total liabilities	—	726,889	11,384	(50,328)	687,945
Total equity	1,387,953	1,314,216	73,737	(1,387,953)	1,387,953
Total liabilities and equity	$ 1,387,953	2,041,105	85,121	(1,438,281)	2,075,898

ANTERO RESOURCES LLC

Notes to Consolidated Financial Statements (Continued)

March 31, 2010 and December 31, 2009

(Unaudited)

(9) Guarantor Subsidiaries (Continued)

Condensed Combining Income Statement
Three months ended March 31, 2009

	Guarantor companies	Nonguarantor company	Eliminations	Total
		(In thousands)		
Revenue:				
Total revenue	$ 82,882	2,092	(3,514)	81,460
Operating expenses:				
Operating expenses	27,626	1,298	(3,514)	25,410
Depletion, depreciation and amortization	38,629	1,072	—	39,701
General and administrative	4,286	120	—	4,406
Total operating expenses	70,541	2,490	(3,514)	69,517
Operating income (loss)	12,341	(398)	—	11,943
Interest and other income (expense), net	(8,553)	—	—	(8,553)
Income before taxes	3,788	(398)	—	3,390
Current tax (expense) benefit	1,605	—	—	1,605
Net income (loss)	5,393	(398)	—	4,995
Noncontrolling interest in net loss of consolidated subsidiary	—	159	—	159
Net income (loss) attributable to Antero stockholders	$ 5,393	(239)	—	5,154

ANTERO RESOURCES LLC

Notes to Consolidated Financial Statements (Continued)

March 31, 2010 and December 31, 2009

(Unaudited)

(9) Guarantor Subsidiaries (Continued)

Condensed Combining Statement of Cash Flows
Three months ended March 31, 2009

	Guarantor companies	Nonguarantor company	Eliminations	Total
		(In thousands)		
Net cash provided by operating activities	$ 70,852	(4,212)	—	66,640
Net cash used in investing activities	(114,843)	(1,627)	1,149	(115,321)
Net cash provided by financing activities	8,538	2,323	(1,149)	9,712
Net increase in cash and cash equivalents	(35,453)	(3,516)	—	(38,969)
Cash and cash equivalents, beginning of year	34,182	4,787	—	38,969
Cash and cash equivalents, end of year	$ (1,271)	1,271	—	—

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ANTERO RESOURCES LLC

Notes to Consolidated Financial Statements (Continued)

March 31, 2010 and December 31, 2009

(Unaudited)

(9) Guarantor Subsidiaries (Continued)

Condensed Consolidating Income Statement
Three months ended March 31, 2010

	Parent company	Guarantor companies	Nonguarantor company	Eliminations	Total
			(In thousands)		
Revenue:					
Total revenue	$ —	173,850	2,594	(2,882)	173,562
Operating expenses:					
Operating expenses	—	22,911	1,067	(2,882)	21,096
Depletion, depreciation and amortization	—	32,047	949	—	32,996
General and administrative	—	4,295	117	—	4,412
Total operating expenses	—	59,253	2,133	(2,882)	58,504
Operating income (loss)	—	114,597	461	—	115,058
Interest and other income (expense), net	—	(14,894)	—	—	(14,894)
Equity in earnings (loss) of subsidiaries	87,605	—	—	(87,605)	—
Income before taxes	87,605	99,703	461	(87,605)	100,164
Income tax expense	—	(11,318)	—	—	(11,318)
Net income (loss)	87,605	88,385	461	(87,605)	88,846
Noncontrolling interest in net loss of consolidated subsidiary	—	(1,241)	—	—	(1,241)
Net income (loss) attributable to Antero stockholders	$ 87,605	87,144	461	(87,605)	87,605

ANTERO RESOURCES LLC

Notes to Consolidated Financial Statements (Continued)

March 31, 2010 and December 31, 2009

(Unaudited)

(9) Guarantor Subsidiaries (Continued)

Condensed Consolidating Statement of Cash Flows
Three months ended March 31, 2010

	Parent company	Guarantor companies	Nonguarantor company	Eliminations	Total
			(In thousands)		
Net cash provided by operating activities	$ —	50,780	1,209	—	51,989
Net cash used in investing activities	—	(65,777)	(212)	—	(65,989)
Net cash provided by financing activities	—	9,645	—	—	9,645
Net increase in cash and cash equivalents	—	(5,352)	997	—	(4,355)
Cash and cash equivalents, beginning of year	—	9,090	1,579	—	10,669
Cash and cash equivalents, end of year	$ —	3,738	2,576	—	6,314

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Report of Independent Registered Public Accounting Firm

Members
Antero Resources LLC:

We have audited the accompanying consolidated balance sheets of Antero Resources LLC (the Company) as of December 31, 2009 and 2008, and the related consolidated statements of operations, members' equity and comprehensive income (loss), and cash flows for each of the years in the three-year period ended December 31, 2009. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Antero Resources LLC as of December 31, 2009 and 2008, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2009, in conformity with U.S. generally accepted accounting principles.

As discussed in note 1 to the consolidated financial statements, Antero Resources LLC adopted the disclosure provisions related to the presentation of minority interest effective January 1, 2009, which have been applied retrospectively in the consolidated financial statements referred to above.

/s/ KPMG LLP

Denver, Colorado
March 30, 2010

ANTERO RESOURCES LLC

Consolidated Balance Sheets

December 31, 2008 and 2009

(In thousands)

	2008	2009
Assets		
Current assets:		
Cash and cash equivalents	$ 38,969	10,669
Accounts receivable—trade, net of allowance for doubtful accounts of $0 and $424 in 2008 and 2009, respectively	53,323	35,897
Accrued revenue	18,805	17,459
Prepaid expenses	7,615	7,419
Derivative instruments	83,608	22,105
Inventories	1,848	1,295
Total current assets	204,168	94,844
Property and equipment:		
Natural gas properties, at cost (successful efforts method):		
Unproved properties	649,605	596,694
Producing properties	1,148,306	1,340,827
Gathering systems and facilities	179,836	185,688
Other property and equipment	3,113	3,302
	1,980,860	2,126,511
Less accumulated depletion, depreciation, and amortization	(183,145)	(322,992)
Property and equipment, net	1,797,715	1,803,519
Derivative instruments	18,672	18,989
Other assets, net	8,412	19,214
Total assets	$ 2,028,967	1,936,566

ANTERO RESOURCES LLC

Consolidated Balance Sheets

December 31, 2008 and 2009

(In thousands)

	2008	2009
Liabilities and Members' Equity		
Current liabilities:		
Accounts payable	$ 143,544	48,594
Accrued expenses	18,098	24,440
Revenue distributions payable	31,463	29,304
Advances from joint interest owners	7,893	1,400
Derivative instruments	7,086	8,623
Capital leases—current	125	132
Total current liabilities	208,209	112,493
Long-term liabilities:		
Bank credit facility	396,580	142,080
Second lien term notes payable	225,000	—
Senior notes	—	372,397
Derivative instruments	10,164	2,464
Asset retirement obligations	3,034	3,487
Deferred tax payable	3,029	424
Capital leases—noncurrent	1,154	1,022
Other long term liabilities	4,242	3,092
Total liabilities	851,412	637,459
Members' equity:		
Preferred stock	1,163,006	—
Common Stock	174	—
Members' equity	—	1,392,833
Capital in excess of par value	332	—
Accumulated deficit	(15,275)	(123,447)
	1,148,237	1,269,386
Noncontrolling interest in consolidated subsidiary	29,318	29,721
Total members' equity	1,177,555	1,299,107
Total liabilities and members' equity	$ 2,028,967	1,936,566

See accompanying notes to consolidated financial statements.

ANTERO RESOURCES LLC

Consolidated Statements of Operations

Years ended December 31, 2007, 2008, and 2009

(In thousands)

	2007	2008	2009
Revenue:			
Natural gas sales	$ 63,975	220,219	123,915
Realized and unrealized gain on commodity derivative instruments (including unrealized gains (losses) of $4,619, $90,301 and $(61,186) in 2007, 2008, and 2009, respectively)	18,992	116,354	55,364
Oil sales	3,749	9,496	5,706
Gas gathering and processing revenue	4,778	20,421	23,005
Total revenue	91,494	366,490	207,990
Operating expenses:			
Lease operating expenses	4,435	13,350	17,606
Gathering, compression and transportation	10,016	29,033	28,190
Production taxes	2,233	10,281	4,940
Exploration expenses	17,970	22,998	10,228
Impairment of unproved properties	4,995	10,112	54,204
Depletion, depreciation and amortization	50,091	124,821	139,813
Accretion of asset retirement obligations	68	176	265
General and administrative	11,682	16,171	20,843
Total operating expenses	101,490	226,942	276,089
Operating income (loss)	(9,996)	139,548	(68,099)
Other income (expense):			
Interest expense	(25,124)	(37,594)	(36,053)
Realized and unrealized gains (losses) on interest derivative instruments, net (including unrealized gains (losses) of $(3,433), $(13,817), and $6,163 in 2007, 2008 and 2009, respectively)	(3,033)	(15,245)	(4,985)
Total other expense	(28,157)	(52,839)	(41,038)
Income (loss) before income taxes	(38,153)	86,709	(109,137)
Income tax (expense) benefit	400	(3,029)	2,605
Net income (loss)	(37,753)	83,680	(106,532)
Noncontrolling interest in net loss of consolidated subsidiary	—	276	363
Net income (loss) attributable to Antero equity owners	$ (37,753)	83,956	(106,169)

See accompanying notes to consolidated financial statements.

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ANTERO RESOURCES LLC
Consolidated Statements of Equity and Comprehensive Income (Loss)
Years ended December 31, 2007, 2008, and 2009
(In thousands)

	Members' equity	Preferred stock	Common stock	Capital in excess of par value	Accumulated deficit	Total Antero equity	Noncontrolling interest	Total equity
Balances, December 31, 2006	$ —	238,385	33	489	(61,479)	177,428	—	177,428
Issuance of preferred stock	—	254,620	—	(5)	—	254,615	—	254,615
Stock compensation	—	—	112	756	—	868	—	868
Stock issuance costs	—	—	—	(856)	—	(856)	—	(856)
Net loss and comprehensive loss	—	—	—	—	(37,753)	(37,753)	—	(37,753)
Balances, December 31, 2007	—	493,005	145	384	(99,232)	394,302	—	394,302
Issuance of preferred stock	—	670,000	—	—	—	670,000	—	670,000
Stock compensation	—	—	29	241	—	270	—	270
Sale of noncontrolling interest in Centrahoma	—	—	—	—	—	—	29,594	29,594
Other	—	—	—	(291)	—	(291)	—	(291)
Net income and comprehensive income	—	—	—	—	83,956	83,956	(276)	83,680
Balances, December 31, 2008	—	1,163,005	174	334	(15,276)	1,148,237	29,318	1,177,555
Issuance of preferred stock, net of issuance costs of $1	—	105,000	—	(1)	—	104,999	—	104,999
Stock compensation	—	—	—	2,822	—	2,822	—	2,822
Cancellation of stock option plan	—	—	—	(1,717)	(2,002)	(3,719)	—	(3,719)
Return of capital to common stockholders	—	—	—	(345)	—	(345)	—	(345)
Exchange of preferred stock and common stock in Antero entities for members' equity in Antero Resources LLC	1,269,272	(1,268,005)	(174)	(1,093)	—	—	—	—
Issuance of equity in LLC, net of issuance costs of $1,439	123,561	—	—	—	—	123,561	—	123,561
Contribution received from noncontrolling interest	—	—	—	—	—	—	766	766
Net loss and comprehensive loss	—	—	—	—	(106,169)	(106,169)	(363)	(106,532)
Balances, December 31, 2009	$ 1,392,833	—	—	—	(123,447)	1,269,386	29,721	1,299,107

See accompanying notes to consolidated financial statements.

ANTERO RESOURCES LLC

Consolidated Statements of Cash Flows

Years ended December 31, 2007, 2008, and 2009

(In thousands)

	2007	2008	2009
Cash flows from operating activities:			
Net income (loss)	$ (37,753)	83,680	(106,532)
Adjustment to reconcile net earnings to net cash provided by operating activities:			
Depletion, depreciation, and amortization	50,091	124,821	139,813
Dry hole costs	4,405	6,582	1,671
Impairment of unproved properties	4,995	10,112	54,204
Accretion of asset retirement obligations	68	176	265
Accretion of bond discount	—	—	26
Amortization and write-off of deferred financing costs	757	1,283	7,268
Amortization of premiums on commodity derivative instruments	453	—	—
Stock compensation	868	269	2,822
Unrealized (gains) losses on derivative instruments, net	1,239	(76,484)	55,023
Deferred taxes	(400)	3,029	(2,605)
Changes in current assets and liabilities:			
Accounts receivable	(23,351)	(17,641)	19,169
Accrued revenue	(6,488)	(3,798)	1,346
Prepaid expenses	(1,386)	(5,973)	196
Inventories	(330)	(1,005)	553
Accounts payable	7,070	3,713	(16,730)
Accrued expenses	13,503	5,984	1,470
Revenue distributions payable	8,980	17,306	(2,159)
Advance from joint interest owners	2,024	5,461	(6,493)
Net cash provided by operating activities	24,745	157,515	149,307
Cash flows from investing activities:			
Proved property acquisitions	(29,074)	(3,466)	(1,029)
Additions to unproved properties	(144,897)	(457,879)	(16,118)
Drilling costs	(335,465)	(512,112)	(258,520)
Additions to gathering systems and facilities	(90,262)	(51,964)	(5,819)
Additions to other property and equipment	(372)	(1,674)	(188)
Increase in other assets	(832)	(1,479)	(225)
Sale of noncontrolling interest in subsidiary	—	24,564	—
Net cash used in investing activities	(600,902)	(1,004,010)	(281,899)
Cash flows from financing activities:			
Borrowings on treasury management revolving note payable, net	6,307	(6,307)	—
Issuance of senior notes	—	—	372,371
Borrowings on bank credit facility	458,460	279,200	170,000
Payments on bank credit facility	(351,580)	(72,000)	(424,500)
Borrowings (repayment) on second lien term note	225,000	—	(225,000)
Payments on capital lease obligations	(111)	(117)	(125)
Payments of deferred financing costs	(6,509)	(758)	(17,845)
Issuance of preferred stock	254,615	670,000	105,000
Issuance of members' equity	—	—	125,000
Net cash received from noncontrolling interest	—	4,623	1,176
Return of capital to common stockholders	—	—	(345)
Equity issuance cost	(856)	(291)	(1,440)
Net cash provided by financing activities	585,326	874,350	104,292
Net increase in cash and cash equivalents	9,169	27,855	(28,300)
Cash and cash equivalents, beginning of year	1,945	11,114	38,969
Cash and cash equivalents, end of year	$ 11,114	38,969	10,669
Supplemental disclosure of cash flow information:			
Cash paid during the year for interest	$ 17,299	38,896	28,395
Supplemental disclosure of noncash investing activities:			
Changes in accounts payable for additions to properties, systems and facilities	$ 46,399	14,653	(78,220)

See accompanying notes to consolidated financial statements.

ANTERO RESOURCES LLC

Notes to Consolidated Financial Statements

December 31, 2007, 2008 and 2009

(1) Organization

(a) Business and Organization

Antero Resources LLC, a limited liability company, and its consolidated operating subsidiaries (collectively referred to as the Company, we, or our) are engaged in the exploration for and the production of natural gas and oil onshore in the United States in unconventional reservoirs, which can generally be characterized as fractured shales and tight sand formations. Our properties are primarily located in the Appalachian Basin in West Virginia and Pennsylvania, the Arkoma Basin in Oklahoma and the Piceance Basin in Colorado. We also have certain midstream gathering and pipeline operations which are ancillary to our interests in producing properties in these basins. Our corporate headquarters are in Denver, Colorado.

Our consolidated financial statements as of December 31, 2009 include the accounts of Antero Resources LLC, and its directly and indirectly owned subsidiaries. The subsidiaries include Antero Resources Corporation (Antero Arkoma), Antero Resources Midstream Corporation (Antero Midstream), Antero Resources Piceance Corporation (Antero Piceance), Antero Resources Pipeline Corporation (Antero Pipeline), Antero Resources Appalachian Corporation (Antero Appalachian), and Antero Resources Finance Corporation (Antero Finance) (collectively referred to as the Antero Entities). The financial statements as of December 31, 2007 and 2008 include the combined accounts of the Antero Entities, when ownership was under common control; the outstanding equity instruments of these operating entities were held by the same individuals or entities in the same percentage. In October 2009, the equity structure was reorganized in a nontaxable transaction by the formation of Antero Resources LLC, which issued units of members' equity to the stockholders of the operating entities in exchange for all of their preferred and common shares in each operating entity. The assets and liabilities of each of the operating entities are included in the 2009 consolidated financial statements at their historical basis.

(b) Centrahoma Processing Joint Venture

On February 11, 2008, Antero Midstream and MarkWest Oklahoma Gas Company, LLC (MarkWest) entered into an Ownership and Operating Agreement resulting in the formation of Centrahoma Processing LLC (Centrahoma). Antero Midstream contributed processing assets with a fair value of $60.5 million, for an 80% ownership, and MarkWest contributed $12.1 million in cash for a 20% ownership, in Centrahoma. On May 9, 2008, MarkWest exercised its option to purchase an additional 20% interest in Centrahoma from Antero Midstream for cash of $12.1 million. At December 31, 2008, Centrahoma is 60% owned by Antero Midstream and 40% owned by MarkWest. Centrahoma is accounted for as a consolidated subsidiary with MarkWest's interest accounted for as a noncontrolling interest in the financial statements.

The Antero Midstream contribution of processing assets was accounted for as a transaction between entities under common control, whereby the assets contributed by Antero Midstream were recorded at their carry-over basis of $58.9 million.

ANTERO RESOURCES LLC

Notes to Consolidated Financial Statements (Continued)

December 31, 2007, 2008 and 2009

(2) Summary of Significant Accounting Policies

(a) Basis of Presentation

The accompanying consolidated financial statements as of December 31, 2009 include the accounts of Antero Resources LLC and its subsidiaries. The 2007 and 2008 financial statements include the combined accounts of the Antero Entities. All significant intercompany accounts and transactions have been eliminated.

As of March 30, 2010, which is the date these financial statements were issued, the Company completed its evaluation of potential subsequent events for disclosure and no items requiring disclosure were identified.

(b) Use of Estimates

The preparation of financial statements in conformity with generally accepted accounting principles in the United States requires management to make estimates and assumptions that affect the reported assets and liabilities and disclosure of contingent assets and liabilities at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the reporting period. Changes in facts and circumstances or discovery of new information may result in revised estimates, and actual results could differ from those estimates.

The Company's financial statements are based on a number of significant estimates including estimates of gas and oil reserve quantities, which are the basis for the calculation of depreciation, depletion, amortization, present value of future reserves, and impairment of oil and gas properties. Reserve estimates by their nature are inherently imprecise.

(c) Risks and Uncertainties

Historically, the market for natural gas has experienced significant price fluctuations. Prices for natural gas have been particularly volatile in recent years. The price fluctuations can result from variations in weather, levels of production in the region, availability of transportation capacity to other regions of the country, and various other factors. Increases or decreases in prices received could have a significant impact on the Company's future results of operations.

(d) Cash and Cash Equivalents

The Company considers all liquid investments purchased with an initial maturity of three months or less to be cash equivalents. The carrying value of cash and cash equivalents approximates fair value due to the short-term nature of these instruments.

(e) Oil and Gas Properties

The Company accounts for its natural gas and crude oil exploration and development activities under the successful efforts method of accounting. Under such method, costs of productive wells, development dry holes, and undeveloped leases are capitalized. Oil and gas lease acquisition costs are also capitalized. Exploration costs, including personnel and other internal costs, geological and geophysical expenses, and delay rentals for gas and oil leases, are charged to expense as incurred. Exploratory drilling costs are initially capitalized, but charged to expense if and when the well is determined not to have found reserves in commercial quantities. The Company reviews exploration costs related to wells-in-progress at the end of each quarter and makes a determination based on known results of drilling at that time whether the costs should continue to be capitalized pending further well testing and results or charged to expense. The sale of a partial interest in a proved property is accounted for as a cost recovery, and no gain or loss is recognized as long as this treatment does not significantly affect the units-of-production amortization rate. A gain or loss is recognized for all other sales of producing properties.

Unproved properties with significant acquisition costs are assessed for impairment on a property-by-property basis, and any impairment in value is charged to expense. Impairment is assessed based on remaining lease terms, drilling results, reservoir performance, commodity price outlooks, and future plans to develop acreage. Other unproved properties are assessed for impairment on an aggregate basis. Unproved properties and the related costs are transferred to proved properties when reserves are discovered on or otherwise attributed to the property. Proceeds from sales of partial interests in unproved properties are accounted for as a recovery of cost without recognizing any gain or loss until the cost has been recovered. Impairment of unproved properties for leases which have expired or are expected to expire was $5.0 million, $10.1 million, and $54.2 million for the years ended December 31, 2007, 2008, and 2009, respectively.

The Company reviews its proved oil and gas properties for impairment whenever events and circumstances indicate that the carrying value of the properties may not be recoverable. When determining whether impairment has occurred, the Company estimates the expected future cash flows of its oil and gas properties and compares such future cash flows to the carrying amount of the properties to determine if the carrying amount is recoverable. If the carrying amount exceeds the estimated undiscounted future cash flows, the Company reduces the carrying amount of the properties to their estimated fair value. The factors used to determine fair value include estimates of proved reserves, future commodity prices, future production estimates, anticipated capital expenditures, and a commensurate discount rate. There were no impairments of proved natural gas properties during the years ended December 31, 2007, 2008, and 2009.

At December 31, 2009, the Company had capitalized costs related to exploratory wells-in-progress, which were pending determination of proved reserves of $11.9 million, primarily related to development activity in the Marcellus Shale. The Company had no costs which have been deferred for longer than one year pending proved reserves at December 31, 2009 and had no significant costs related to wells in progress at December 31, 2007 and 2008 pending determination of whether proved reserves could be assigned.

The provision for depreciation, depletion, and amortization of oil and gas properties is calculated on a geological reservoir basis using the units-of-production method. Depreciation, depletion, and amortization expense for oil and gas properties was $44.1 million, $116.9 million, and $130.1 million for the years ended December 31, 2007, 2008, and 2009, respectively.

(f) Inventories

Inventories consist of chemicals, pipe and flow meters, and are stated at the lower of cost or market. Cost is determined using the first-in, first-out (FIFO) method.

ANTERO RESOURCES LLC

Notes to Consolidated Financial Statements (Continued)

December 31, 2007, 2008 and 2009

(2) Summary of Significant Accounting Policies (Continued)

(g) Gathering Systems and Processing Facilities

Gathering systems, compressors, and processing facilities are depreciated using the straight-line method over their estimated useful life of 20 years. Expenditures for installation, major additions, and improvements are capitalized, and minor replacements, maintenance, and repairs are charged to expenses as incurred. For the years ended December 31, 2007, 2008, and 2009, depreciation expense for gathering systems and processing facilities was $5.7 million, $7.5 million, and $9.0 million, respectively. A gain or loss is recognized upon the sale or disposal of property and equipment.

(h) Impairment of Long-Lived Assets Other than Oil and Gas Properties

The Company evaluates its long-lived assets other than natural gas properties for impairment when events or changes in circumstances indicate that the related carrying amount of the assets may not be recoverable. Generally, the basis for making such assessments is undiscounted future cash flow projections for the unit being assessed. If the carrying value amounts of the assets are deemed to be not recoverable, the carrying amount is reduced to the estimated fair value, which is based on discounted future cash flows or other techniques, as appropriate. No impairments for such assets have been recorded through December 31, 2009.

(i) Other Property and Equipment

Other property and equipment, consisting of vehicles and office equipment, is depreciated using the straight-line method over estimated useful lives ranging from three to five years. For the years ended December 31, 2007, 2008, and 2009, depreciation expense for other property and equipment was $302,000, $390,000, and $660,000, respectively. A gain or loss is recognized upon the sale or disposal of property and equipment.

(j) Deferred Financing Costs

Deferred financing costs represent loan origination fees, initial purchasers' discounts, and other borrowing costs and are included in noncurrent other assets on the consolidated balance sheet. These costs are being amortized over the term of the notes using the effective interest method. The Company charges interest expense for deferred financing costs remaining for debt facilities that have been retired prior to their maturity date and for deferred charges relating to parties to its bank credit facility who do not continue to participate. The amounts amortized and the write-off of previously deferred debt issuance costs was $0.8 million, $1.3 million, and $7.3 million for the years ended December 31, 2007, 2008, and 2009, respectively.

(k) Derivative Financial Instruments

In order to manage its exposure to oil and gas price volatility, the Company enters into derivative transactions from time to time, including commodity swap agreements, collar agreements, and other similar agreements relating to natural gas expected to be produced. From time to time, the Company also enters into derivative contracts to mitigate the effects of interest rate fluctuations. To the extent legal right of offset with a counterparty exists, the Company reports derivative assets and liabilities on a net basis. The Company has exposure to credit risk to the extent the counterparty is unable to satisfy

(2) Summary of Significant Accounting Policies (Continued)

its settlement obligation. The Company actively monitors the credit worthiness of each counterparty and assesses the impact, if any, on its derivative position.

The Company records derivative instruments on the balance sheet as either an asset or liability measured at fair value and records changes in the fair value of derivatives in current earnings as they occur. Changes in the fair value of commodity derivatives are classified as revenues, and changes in the fair value of interest rate derivatives are classified as other income (expense).

(l) Asset Retirement Obligations

The Company is obligated to dispose of certain long-lived assets upon their abandonment. The Company's asset retirement obligations (ARO) relate primarily to its obligation to plug and abandon oil and gas wells at the end of their life. The ARO is recorded at its estimated fair value, measured by reference to the expected future cash outflows required to satisfy the retirement obligation discounted at the Company's credit-adjusted, risk-free interest rate. Revisions to estimated AROs can result from changes in retirement cost estimates, revisions to estimated inflation rates, and changes in the estimated timing of abandonment. The fair value of the liability is added to the carrying amount of the associated asset, and this additional carrying amount is depreciated over the life of the asset. The liability is accreted at the end of each period through charges to operating expense. If the obligation is settled for an amount other than the carrying amount of the liability, we will recognize a gain or loss on settlement.

The Company gathers and processes natural gas through its midstream and gathering assets. We may become obligated by regulatory requirements to remove certain facilities or perform other remediation upon retirement of these assets. However, the Company is not able to reasonably determine the fair value of the asset retirement obligations since future dismantlement and removal dates are indeterminate. The Company does not have access to adequate forecasts that predict the timing of expected production for existing reserves on those fields in which Company operates. In the absence of such information, the Company is not able to make a reasonable estimate of when future dismantlement and removal dates will occur and will continue to monitor regulatory requirements to remove its midstream facilities.

(m) Environmental Liabilities

Environmental expenditures that relate to an existing condition caused by past operations and that do not contribute to current or future revenue generation are expensed as incurred. Liabilities are accrued when environmental assessments and/or clean up is probable, and the costs can be reasonably estimated. These liabilities are adjusted as additional information becomes available or circumstances change. As of December 31, 2008 and 2009, the Company has not accrued for any environmental liabilities nor has it been fined or cited for any environmental violations that could have a material adverse effect on future capital expenditures or operating results of the Company.

(n) Natural Gas and Oil Revenues

The Company utilizes the accrual method of accounting for oil and natural gas revenues, whereby revenues are recognized as the Company's entitlement share of oil and natural gas is produced based

(2) Summary of Significant Accounting Policies (Continued)

on its working interests in the properties. The Company records a receivable (payable) to the extent it receives less (more) than its proportionate share of oil and natural gas revenues. At December 31, 2008 and 2009, the Company had no significant imbalance positions.

(o) Gathering and Processing Fees Revenue

The Company utilizes the accrual method of accounting for gas processing fee revenues. The amount of revenue is determinable when the sale of the applicable product has been completed, and delivery and transfer of title at the tailgate of the plants. Service fees are recognized as revenue when services are performed.

The Company obtains access to unprocessed natural gas and provides services to customers under a processing agreement. The processing agreement contains a fee-based provision, whereby the Company receives a fee based on the volume of natural gas processed. In addition, proceeds from selling NGLs are remitted back to customers based on a contractual calculation of the liquids available for separation, as determined from an analysis of the raw natural gas received. The margin earned on NGLs sold in excess of payments made to the customers is not directly dependant on the value of these products and is reported net.

(p) Concentrations of Credit Risk

The Company's revenues are derived principally from uncollateralized sales to purchasers in the oil and gas industry. The concentration of credit risk in a single industry affects the Company's overall exposure to credit risk because purchasers may be similarly affected by changes in economic and other conditions. The Company has not experienced significant credit losses on its receivables.

The Company's sales to major customers (purchases in excess of 10% of total sales) for the years ended December 31, 2007, 2008, and 2009 are as follows:

	2007	2008	2009
Company A	70%	49%	44%
Company B	22	41	15
Company C	—	—	12
All others	8	10	29
	100%	100%	100%

Although a substantial portion of production is purchased by these major customers, we do not believe the loss of any one or several customers would have a material adverse effect on our business, as other customers or markets would be accessible to us.

The Company, at times, may have cash in banks in excess of federally insured amounts.

ANTERO RESOURCES LLC

Notes to Consolidated Financial Statements (Continued)

December 31, 2007, 2008 and 2009

(2) Summary of Significant Accounting Policies (Continued)

(q) Stock Compensation

Awards of profits units to the Antero Resources Employee Holdings LLC (Antero Holdings) are classified as liability instruments. Compensation expense for these awards is recognized when all performance, market, and service conditions are probable of being satisfied.

Prior to the formation of Antero Resources LLC, the Antero Entities granted various equity awards to certain employees. The estimated fair value of restricted stock at the date of the award is charged to expense over the vesting period of the award. The estimated fair value of stock option awards is charged to expense over the service period of the award. Fair value of stock option awards is estimated using the Black Scholes option pricing model. These awards were canceled in connection with the reorganization of the Company's ownership structure in November 2009.

(r) Income Taxes

Antero Resources LLC and each of its operating subsidiaries file separate federal and state income tax returns. Antero Resources LLC is a partnership for income tax purposes and therefore is not subject to federal or state income taxes. The tax on the income of Antero Resources LLC is borne by the individual members through the allocation of taxable income.

The Company's operating subsidiaries recognize deferred tax assets and liabilities for temporary differences resulting from net operating loss carryforwards for income tax purposes and the differences between the financial statement and tax basis of assets and liabilities. The effect of changes in the tax laws or tax rates is recognized in income in the period such changes are enacted. Deferred tax assets are reduced by a valuation allowance, when, in the opinion of management, it is more likely than not that some portion or all of the deferred tax assets will not be realized.

Unrecognized tax benefits represent potential future tax obligations for uncertain tax positions taken on previously filed tax returns that may not ultimately be sustained. The Company recognizes interest expense related to unrecognized tax benefits in interest expense and fines and penalties as income tax expense. At December 31, 2009 and 2008, the Company has no unrecognized tax benefits from uncertain tax positions that would impact the Company's effective tax rate and has made no provisions for interest or penalties related to uncertain tax positions. The tax years 2006 through 2009 remain open to examination by the U.S. Internal Revenue Service. The Company files tax returns with various state taxing authorities which remain open to examination for tax years 2005 through 2009.

(s) Fair Value Measures

FASB ASC Topic 820, *Fair Value Measurements and Disclosures*, clarifies the definition of fair value, establishes a framework for measuring fair value, and expands disclosures about fair value measurements. This guidance also relates to all nonfinancial assets and liabilities that are not recognized or disclosed on a recurring basis (e.g., those measured at fair value in a business combination, the initial recognition of asset retirement obligations, and impairments of proved oil and gas properties, and other long-lived assets). The fair value is the price that the Company estimates would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. A fair value hierarchy is used to prioritize input to valuation techniques used to estimate fair value. An asset or liability subject to the fair value

ANTERO RESOURCES LLC

Notes to Consolidated Financial Statements (Continued)

December 31, 2007, 2008 and 2009

(2) Summary of Significant Accounting Policies (Continued)

requirements is categorized within the hierarchy based on the lowest level of input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input to the fair value measurement in its entirety requires judgment and considers factors specific to the asset or liability. The highest priority (Level 1) is given to unadjusted quoted market prices in active markets for identical assets or liabilities, and the lowest priority (Level 3) is given to unobservable inputs. Level 2 inputs are data, other than quoted prices included within Level 1, that are observable for the asset or liability, either directly or indirectly. Instruments which are valued using Level 2 inputs include nonexchange traded derivatives such as over-the-counter commodity price swaps, basis swaps, and interest rate swaps. Valuation models used to measure fair value of these instruments consider various Level 2 inputs including (i) quoted forward prices for commodities, (ii) time value, (iii) quoted forward interest rates, (iv) current market prices and contractual prices for the underlying instruments, (v) risk of nonperformance by the Company and the counterparty, (vi) and other relevant economic measures. The Company utilizes its counterparties to assess the reasonableness of its prices and valuation techniques. To the extent a legal right of offset with a counterparty exists, the derivative assets and liabilities are reported on a net basis.

(t) Industry Segment and Geographic Information

We have evaluated how the Company is organized and managed and have identified one operating segment—the exploration and production of oil, natural gas, and natural gas liquids. We consider our gathering, processing and marketing functions as ancillary to our oil and gas producing activities. All of our assets are located in the United States and all of our revenues are attributable to United States customers.

(u) Newly Adopted Accounting Pronouncements

Noncontrolling Interests in Consolidated Financial Statements—In December 2007, the FASB issued new rules which established accounting and reporting standards for noncontrolling interests (minority interests) in subsidiaries. These rules clarified that a noncontrolling interest in a subsidiary should be accounted for as a component of equity separate from the parent's equity. The rules were effective for us on January 1, 2009 and must be applied prospectively, except for the presentation and disclosure requirements, which have been applied retrospectively. The adoption of these rules had the effect of increasing total equity by the amount of the noncontrolling interest and changing other presentations in the accompanying financial statements.

Accounting Standards Codification—In June 2009, the FASB approved the FASB Accounting Standards Codification (ASC), which after its launch on July 1, 2009 became the single source of authoritative, nongovernmental U.S. Generally Accepted Accounting Principles (GAAP). The Codification reorganizes all previous U.S. GAAP pronouncements into roughly 90 accounting topics and displays all topics using a consistent structure. All existing standards that were used to create the Codification are now superseded, replacing the previous references to specific Statements of Financial Accounting Standards with numbers used in the Codification's structural organization.

Modernization of Oil and Gas Reporting—On December 31, 2008, the SEC published final rules and interpretations, the Modernization of Oil and Gas Reporting Requirements, updating its oil and gas

(2) Summary of Significant Accounting Policies (Continued)

reporting requirements. Many of the revisions are updates to definitions in the existing oil and gas rules to make them consistent with the Petroleum Resource Management System, which is a widely accepted standard for the management of petroleum resources that was developed by several industry organizations. Key revisions include the ability to include nontraditional resources in reserves, the use of new technology for determining reserves, permitting disclosure of probable and possible reserves, and changes to the pricing used to determine reserves based on a 12-month average price rather than a period-end spot price. The average is to be calculated using the first-day-of-the-month price for each of the 12 months that make up the reporting period. The new rules are effective for annual reports for fiscal years ending on or after December 31, 2009. In January 2009, the FASB issued Accounting Standards Update 2010-03 *Extractive Industries—Oil and Gas*, to align its rules for oil and gas reserve estimation and disclosure requirements with the SEC's modernization rule. The Company has adopted these new rules in estimating its December 31, 2009 oil and gas reserves and related disclosures and in calculating its 2009 units-of-production method depreciation and depletion expense for the fourth quarter of 2009.

(3) Acquisitions

Much of the Company's acquisition and development activity in the Arkoma and Piceance Basins has been through the acquisition of unproved properties involving individually insignificant costs and subsequent Company-operated drilling and development activity on internally generated prospects on those properties. The following describes significant transactions to acquire unproved and proved properties during the three years ended December 31, 2009:

Antero Arkoma—On December 4, 2007, Antero Arkoma acquired approximately 6,000 net acres and various nonoperating working interests in approximately 60 wells in Coal and Hughes Counties, Oklahoma. The purchase price was approximately $61 million, including purchase price adjustments of approximately $5 million. The operational results of the acquisition were included in the consolidated operations from the date of acquisition, December 4, 2007. The allocation of the purchase price was approximately $38 million for unevaluated leasehold costs, and $28 million for proved properties.

Antero Piceance—In July 2008, Antero Piceance acquired 21 producing wells, unproved acreage, and the related gathering assets in Garfield County, Colorado for $39.2 million. The allocation of the purchase price was approximately $35.7 million for nonproducing leasehold costs and $3.5 million for proved properties.

Antero Appalachian—On September 30, 2008, Antero Appalachian acquired deep rights in properties, including the Marcellus Shale formation on approximately 114,000 net acres in the Appalachian Basin in southwestern Pennsylvania and northern West Virginia. The purchase price was approximately $347 million and was allocated to unproved property. The acquisition agreement contains various drilling commitments which requires Antero Appalachian to drill 179 wells at an estimated maximum cost of approximately $625 million between January 1, 2009 and June 30, 2018 at structured intervals. If the Company does not fulfill its drilling commitments, portions of the unproved property may revert to the seller.

ANTERO RESOURCES LLC

Notes to Consolidated Financial Statements (Continued)

December 31, 2007, 2008 and 2009

(4) Credit Facilities

(a) Bank Credit Facility

The Company has entered into a credit agreement (Credit Facility), which provides for loans up to $400 million. The borrowings under the Credit Facility are subject to borrowing base limitations based on the collateral value of our proved reserves and are subject to regular semiannual redeterminations. The next semiannual redetermination of our borrowing base is scheduled to occur in May 2010. The borrowing base at December 31, 2009 was $400 million; subsequent to the issuance of $150 million of senior notes in January 2010, the borrowing base was reduced to $369 million.

The Credit Facility is secured by mortgages on substantially all of the Company's properties and guarantees from the Company's operating subsidiaries. All advances are due and payable on March 15, 2012. The Credit Facility contains certain covenants, including restrictions on indebtedness and dividends, and requirements with respect to working capital and leverage ratios. Interest is payable at a variable rate based on LIBOR or the prime rate based on the Company's election at the time of borrowing. The Company is in compliance with its financial debt covenants as of December 31, 2009.

As of December 31, 2009, the Company had an outstanding balance under the Credit Facility of $142.1 million with a weighted average interest rate of 2.36%. The Company pays commitment fees of up to 0.50% of the unused borrowing base. In addition, the Company had approximately $3.0 million in outstanding letters of credit under the facility at December 31, 2009. Outstanding borrowings at December 31, 2008 were $399.6 million, including $3.0 million of letters of credit.

(b) Senior Notes

On November 17, 2009, a newly formed wholly owned subsidiary of Antero Resources LLC, Antero Finance, issued $375 million of 9.375% senior notes due December 1, 2017 at a discount of $2.6 million. In January 2010, the Company issued an additional $150 million of the same series of 9.375% senior notes at a premium of $6 million. The notes are unsecured and subordinate to the Company's bank credit facility to the extent of the value of the collateral securing the bank credit facility. The notes are guaranteed on a senior unsecured basis by Antero Resources LLC, all of its wholly owned subsidiaries (other than Antero Finance), and certain of its future restricted subsidiaries. Interest on the notes is payable on June 1 and December 1 of each year, commencing on June 1, 2010. Antero Finance may redeem all or part of the notes at any time on or after December 1, 2013 at redemption prices from 104.688% on or after December 1, 2013 to 100.00% on or after December 1, 2015. In addition, on or before December 1, 2012, Antero Finance may redeem up to 35% of the aggregate principal amount of the notes with the net cash proceeds of certain equity offerings, if certain conditions are met, at a redemption price of 109.375%. At any time prior to December 1, 2013, Antero Finance may also redeem the notes, in whole or in part, at a price equal to 100% of the principal amount of the notes plus a "make-whole" premium. If Antero Resources LLC undergoes a change of control, Antero Finance may be required to offer to purchase notes from the holders.

The Company incurred underwriting discounts and other offering costs aggregating approximately $11.4 million, which were recorded as deferred financing costs in other long-term assets and are being amortized over the life of the notes using the effective interest method.

ANTERO RESOURCES LLC

Notes to Consolidated Financial Statements (Continued)

December 31, 2007, 2008 and 2009

(4) Credit Facilities (Continued)

(c) Second Lien Term Loan

The outstanding balance of the term loan facility of $225 million was retired from the proceeds of the 9.375% senior note offering. The seven-year term loan was entered into by certain of the operating subsidiaries in April 2007 and was secured by second mortgages on substantially all of assets of the participating subsidiaries. The loan had an interest rate of LIBOR plus 4.50%; the weighted average interest rate on advances under the loan was 8.4% at December 31, 2008 and 9.8% at December 31, 2007.

(d) Capital Leases

The Company leases certain compressors under agreements that are classified as capital leases. The cost of equipment under capital leases is included in property and equipment and was approximately $1.5 million at December 31, 2008 and 2009. Accumulated amortization of the leased equipment at December 31, 2008 and 2009 was approximately $158,000 and $234,000, respectively. Amortization of assets under capital leases is included in depreciation expense.

The following represents the future minimum lease payments remaining under capital leases as of December 31, 2009 (in thousands):

2010	$ 196
2011	196
2012	196
2013	196
2014	196
Thereafter	428
Total	1,408
Amount representing interest	254
Present value of minimum lease payments	1,154
Less current portion of obligations under capital leases	132
Noncurrent portion of obligations under capital leases	$ 1,022

(5) Asset Retirement Obligations

The following is a reconciliation of the Company's asset retirement obligations for the years ended December 31, 2008 and 2009 (in thousands).

	2008	2009
Asset retirement obligations—beginning of year	$ 1,340	3,034
Obligations incurred	1,518	188
Accretion expense	176	265
Asset retirement obligations—end of year	$ 3,034	3,487

The fair value of obligations incurred are valued utilizing Level 3 inputs.

ANTERO RESOURCES LLC

Notes to Consolidated Financial Statements (Continued)

December 31, 2007, 2008 and 2009

(6) Reorganization of Ownership Structure

Since the inception of the Antero Entities in 2004, it has raised capital from private equity, institutional, and management investors through the issuance of various classes of preferred stock and common stock by the Antero Entities, each of which were owned by the same investors having substantially identical ownership in each of the entities. The Company also awarded preferred stock and common stock shares to various management and employees in the form of restricted share awards with restrictions that lapse over time. The Company also granted options to purchase shares of common stock to various management and employees.

On November 3, 2009, the stockholders of the Antero Entities contributed their shares of preferred stock and common stock to a newly formed entity, Antero Resources LLC, in exchange for an equivalent number of class I-1, I-2, and I-3 units and class A-1, A-3, B-1, B-3, and B-5 units in the LLC. The newly issued units in Antero Resources LLC are substantially similar in character to the contributed stock in the Antero Entities, including the relative rights in the equity of the newly formed LLC. The exchange was accounted for at the historical amounts recorded for the common stock and preferred stock and the basis in the assets of the Antero Entities was not changed. Outstanding stock options were canceled and the Company agreed to pay the excess of the fair value of the underlying stock over the exercise price of the options to the employees in cash in 2010.

Antero Resources LLC also issued Class A-2, A-4, B-2, B-3, B-4, and B-5 profits units to Antero Holdings, a newly formed limited liability company owned by certain officers and employees. AREH issued similar profits units to its members. Net profits units participate only in distributions upon liquidation events meeting requisite financial return thresholds.

Additionally, in November 2009 Antero Resources LLC issued units in a new class I-4 for $125 million and incurred approximately $1.4 million of offering costs for the new units. The proceeds of this equity placement were used to repay a portion of the borrowings outstanding under the senior secured revolving credit facility.

At December 31, 2009, the outstanding units in Antero Resources LLC are summarized as follows:

	Units authorized and issued
Class I units	103,466,666
Class A and B units	36,193,071
Class A and B profits units	19,726,873
	159,386,610

At December 31, 2009, 202,261 units are outstanding and not vested under the terms of the preferred and common stock awards in the Antero Entities for which they were exchanged.

None of the three classes of outstanding units are entitled to current cash distributions or are convertible into indebtedness. The Company has no obligation to repurchase these units at the election of the unitholders.

In the event of a distribution from Antero Resources LLC, amounts available for distribution are distributed according to a formula set forth in the LLC agreement that takes into account the relative

(6) Reorganization of Ownership Structure (Continued)

priority of the various classes of units outstanding. In the event of a distribution due to the disposition of an individual Antero Entity, a portion of the proceeds is allocated to the employees of the Company based on a requisite return financial threshold. In general, distributions are made first to holders of the Class I units until they have received their investment amount and an 8% special allocation and then, as a group, to the holders of all classes of units together. The Class I units participate on a pro rata basis with the other classes of units in funds available for distributions in excess of the Class I unit investment and special allocation amounts.

At December 31, 2009, the Class I units have an aggregate liquidation priority, including the special allocation of 8% per annum, of $1.6 billion.

(7) Combined Equity Structure of the Antero Entities

Prior to the reorganization of the ownership structure, the financial statements of the Antero Entities were presented on a combined basis. The equity structure of these combined entities is described below.

(a) Preferred Stock

The preferred stock had been issued to various private equity, institutional, and management investors periodically since 2004. The Series A Preferred Stock was issued for a total of $268 million, and the Series B was issued for a total of $1 billion. Both Series A and B accumulated dividends at 8% per annum compounded quarterly. Series C Preferred Stock was issued for no consideration to management members who were investors in the Series B Preferred Stock and vested over a four-year period. Both Series A and B were convertible into one share of common stock plus an amount payable in cash and, in the event of a public offering, to additional shares of common stock equal to the purchase price plus accumulated unpaid dividends. Upon a liquidation event (as defined), holders of Series A and B were entitled to receive, prior to any amounts received by the common stockholders, an amount equal to the purchase price plus accumulated unpaid dividends and participated with common stockholders in any excess funds available in liquidation as if the share were converted to common shares. The Series A and B Preferred Shares also had voting rights on all matters submitted to stockholders for vote as if the shares were converted to common shares. None of the three classes of preferred stock were entitled to current cash distributions or were convertible into indebtedness. The Company had no obligation to repurchase the preferred stock at the election of the stockholders.

The following table sets forth the combined Series A, B and C Preferred Stock outstanding for the Antero Entities at December 31, 2008:

	Shares
Series A	26,800,000
Series B	59,666,666
Series C	1,333,333

ANTERO RESOURCES LLC

Notes to Consolidated Financial Statements (Continued)

December 31, 2007, 2008 and 2009

(7) Combined Equity Structure of the Antero Entities (Continued)

(b) Common Stock

The common stock had been issued to management members and were subject to restrictions which lapsed over a four-year period. Upon a liquidation event, the terms provided for the restrictions to lapse and for the common stock to participate in distributions upon liquidation events when certain requisite financial return thresholds were met. The grants were accounted for as equity based compensation and expense was recognized based on the fair value on the date of grant. See note 9—Stock Compensation.

The following table shows the authorized and issued shares of common stock at December 31, 2008:

	Authorized	Outstanding
Class A Common Stock	160,900,000	21,842,000
Class B Common Stock	11,100,000	11,100,000
Class C Common Stock	625,766,393	83,333,335
Class D Common Stock	31,746,035	30,813,495
Class E Common Stock	42,735,045	26,616,025

(8) Stock Compensation

Prior to the reorganization of the ownership structure described in note 6, the Antero Entities had granted various equity compensation awards in the form of restricted shares of preferred and common stock as well as stock options. The restricted share awards were exchanged for restricted units in Antero Resources LLC. The stock option plans were terminated and the Company agreed with the holders to cash settle the options for the difference between the fair market value of the stock underlying the options at the date of the plan termination and the exercise price of the options. The plan termination liabilities in the amount of $3.7 million were accrued as a liability and charged to additional paid-in capital at the date of termination of the plans. Unamortized stock option expense related to the terminated options of $440,000 at the date of termination of the plans was charged to stock compensation expense.

The Antero Entities had reserved 3,240,000 shares of Class A common stock and 12,881,562 shares of Class C common stock for the granting of options to directors, consultants, and employees. The term of the options was seven years and the options vested in equal installments over four years from the earlier of the optionee's original date of employment or grant date.

The fair value of each option award was estimated on the date of grant using the Black-Scholes option pricing model and the weighted average assumptions in the following table. The Company used historical data to estimate the expected term of the option, such as employee option exercise and employee post-vesting departure behavior. The Company used peer group data to estimate volatility. Separate groups of employees that have similar historical exercise behavior were considered separately for valuation purposes. The risk-free rate for the expected term of the option was based on the U.S. Treasury yield curve in effect at the time of grant. The Company granted certain options at the date of the reorganization of the ownership structure described in note 6, which were 100% vested at the date

ANTERO RESOURCES LLC

Notes to Consolidated Financial Statements (Continued)

December 31, 2007, 2008 and 2009

(8) Stock Compensation (Continued)

of grant. The Company charged compensation expense for these option grants for $1.3 million, the amount which the Company agreed to settle the options for at the date of the reorganization.

	2007	2008
Valuation assumptions:		
Expected dividend yield	None	None
Expected volatility	22.37% - 40.16%	22.00% - 40.00%
Expected term (years)	4.75	4.75
Risk-free interest rate	4.50%	1.52% - 3.49%

Stock Compensation Expense

Stock compensation expense and unamortized equity compensation is summarized as follows (in thousands):

Equity-based compensation expense:	
Year ended December 31, 2009:	
Preferred stock awards	$ 189
Common stock awards	623
Stock options	2,010
Total stock-based compensation expense	$ 2,822
Year ended December 31, 2008:	
Preferred stock awards	$ 30
Common stock awards	(45)
Stock options	285
Total stock-based compensation expense	$ 270
Year ended December 31, 2007:	
Preferred stock awards	$ 113
Common stock awards	524
Stock options	231
Total stock-based compensation expense	$ 868
Unamortized equity compensation expense at December 31, 2009:	
Preferred stock awards	$ —
Common stock awards	—

(8) Stock Compensation (Continued)

Stock option activity for each of the Antero Entities during the year ended December 31, 2009 is as follows:

	Antero Arkoma	Antero Piceance	Antero Midstream	Antero Pipeline	Antero Appalachian	Combined number of shares	Weighted average exercise price
Options outstanding for Class A common stock:							
Balance at December 31, 2008	692,028	358,372	37,074	16,476	—	1,103,950	$ 2.90
Granted	—	—	5,509	31,882	—	37,391	16.30
Forfeited	—	—	—	—	—	—	—
Canceled	(692,028)	(358,372)	(42,583)	(48,358)	—	(1,141,341)	3.34
Balance at December 31, 2009	—	—	—	—	—	—	
Weighted average grant date fair value of shares granted (per share):							
2009	$ —	—	18.51	36.52	—		
2008	5.74	0.58	0.12	0.12	—		
2007	1.01	0.01	44.42	6.67	—		

	Antero Arkoma	Antero Piceance	Antero Midstream	Antero Pipeline	Antero Appalachian	Combined number of shares	Weighted average exercise price
Options outstanding for Class C common stock:							
Balance at December 31, 2008	1,708,907	1,361,785	133,508	—	2,136,133	5,340,333	$ 11.50
Granted	2,560	2,040	45,062	—	3,200	52,862	6.73
Forfeited	(10,240)	(8,160)	(800)	—	(12,800)	(32,000)	23.44
Cancelled	(1,701,227)	(1,355,665)	(177,770)	—	(2,126,533)	(5,361,195)	9.54
Balance at December 31, 2009	—	—	—	—	—	—	
Weighted average grant date fair value of shares granted (per share):							
2009	$ 4.00	0.78	17.56	—	1.57		
2008	0.27	0.66	4.40	—	0.01		
2007	0.29	0.05	0.01	—	—		

(9) Profits Units Awards

In connection with the reorganization of the Company's ownership structure in November 2009 and cancellation of the stock option plans, the Company issued profits units to a newly formed limited liability company (Antero Holdings) owned by certain officers and employees. The profit units participate only in distributions from Antero Resources LLC in liquidation events, meeting requisite financial thresholds after the Class I and other classes of unitholders have recovered their investment and special allocation amounts. The profits units have no voting rights. Compensation expense for these awards will be recognized when all performance, market, and service conditions are probable of being

ANTERO RESOURCES LLC

Notes to Consolidated Financial Statements (Continued)

December 31, 2007, 2008 and 2009

(9) Profits Units Awards (Continued)

satisfied (in general, upon a liquidating event). Accordingly, no value was assigned to the units when issued. A summary of the status of the net profits units outstanding in Antero Holdings and changes during the year ended December 31, 2009 is summarized as follows:

	Units
Balance, January 1, 2009	—
Granted	6,625,283
Vested	(4,000,117)
Nonvested at December 31, 2009	2,625,166

(10) Financial Instruments

The carrying values of trade receivables, trade payables, the credit facility, and the term loan at December 31, 2009 and 2008 approximated market value. The carrying value of the bank credit facility at December 31, 2009 approximated fair value because the variable interest rates are reflective of current market conditions.

The fair value of the Company's senior notes was approximately $382.5 million, based on market data at December 31, 2009.

See note 11 for information regarding the fair value of derivative financial instruments.

(11) Derivative Instruments

Commodity Derivatives

The Company periodically enters into natural gas derivative contracts with counterparties to hedge the price risk associated with a portion of its production. These derivatives are not held for trading purposes. To the extent that changes occur in the market prices of natural gas, the Company is exposed to market risk on these open contracts. This market risk exposure is generally offset by the change in market prices of natural gas recognized upon the ultimate sale of the natural gas produced.

For the years ended December 31, 2007, 2008 and 2009, the Company was party to natural gas fixed price swaps. When actual commodity prices exceed the fixed price provided by the swap contracts, the Company pays the excess to the counterparty, and when actual commodity prices are below the contractually provided fixed price receives the difference from the counterparty. The Company's natural gas swaps have not been designated as hedges for accounting purposes; therefore, all gains and losses were recognized in income currently.

As of December 31, 2009, derivative positions with JP Morgan accounted for approximately 87% of the net fair value of our commodity derivative assets position. Derivative positions with BNP Paribas, Key Bank N.A., and Well Fargo accounted for the remainder. The Company has no collateral from any counterparties. Commodity and interest rate derivative positions are with institutions who have a position in our Credit Facility and are secured by the collateral pledged on the Credit Facility and cross default provisions between the Credit Facility and the derivative instruments. There are no past due receivables from or payables to any of our counterparties.

ANTERO RESOURCES LLC

Notes to Consolidated Financial Statements (Continued)

December 31, 2007, 2008 and 2009

(11) Derivative Instruments (Continued)

Through December 31, 2009, and including swaps entered into since December 31, 2009 through March 30, 2010, the Company has entered into fixed price natural gas swaps in order to hedge a portion of its natural gas production from January 1, 2010 through December 31, 2014 as summarized in the following table. Hedge agreements referenced to the Centerpoint, NYMEX, and Transco Zone 4 indices are for production in the Arkoma Basin. Hedge agreements referenced to the CIG index are for production in the Piceance Basin. Hedge agreements referenced to the CGTAP index are for production from the Appalachian Basin.

	MMbtu/day	Weighted average index price
Year ended December 31, 2010:		
Centerpoint	30,000	$ 7.33
CIG	30,000	5.54
NYMEX	10,000	6.14
CGTAP	20,000	5.92
Year ending December 31, 2011:		
CIG	35,000	$ 5.78
Transco zone 4	35,000	6.91
CGTAP	30,000	6.60
Year ending December 31, 2012:		
CIG	35,000	$ 6.06
Transco zone 4	35,000	7.05
CGTAP	20,000	6.94
Year ending December 31, 2013:		
CIG	30,000	$ 6.02
Transco zone 4	40,000	6.51
CGTAP	20,000	6.83
Year ending December 31, 2014:		
CIG	40,000	$ 6.07
Transco zone 4	20,000	6.51
CGTAP	40,000	6.53
Centerpoint	10,000	6.20

ANTERO RESOURCES LLC

Notes to Consolidated Financial Statements (Continued)

December 31, 2007, 2008 and 2009

(11) Derivative Instruments (Continued)

Interest Rate Derivatives

The Company has entered into various floating-to-fixed interest rate swap derivative contracts to manage exposures to changes in interest rates from variable rate obligations under the second lien term loan and the bank credit facility. Under the swaps, the Company makes payments to the swap counterparty when the variable LIBOR three-month rate falls below the fixed rate or receives payments from the swap counterparty when the variable LIBOR three-month rate goes above the fixed rate. The outstanding swap agreements during the year ended December 31, 2009 are summarized as follows:

Notional amount of swap	Covering periods	Fixed rate
$225 million	May 2007 to July 1, 2011	4.11%
$150 million	April 1, 2008 to April 1, 2010	2.8025%
$51 million	December 10, 2008 to December 10, 2009	2.79%

When the Company retired the floating rate second lien term loan of $225 million out of the proceeds from the rate 9.375% senior notes in November 2009, it did not terminate the $225 million floating-to-fixed rate swap associated with this debt; therefore, this swap does not have debt associated with it.

At December 31, 2009, the Company had a notional amount of $150.0 million of interest rate swaps related to is credit facility, which had $142.1 million outstanding.

Summary

The following is a summary of the fair values of derivative instruments not designated as hedges for accounting purposes and where such values are recorded in the consolidated balance sheets as of December 31, 2008 and 2009. None of the Company's derivative instruments are designated as hedges for accounting purposes.

	2008		2009	
	Balance sheet location	Fair value	Balance sheet location	Fair value
		(In thousands)		(In thousands)
Asset derivatives not designated as hedges for accounting purposes:				
Commodity contracts	Current assets	$ 83,608	Current assets	$ 22,105
Commodity contracts	Long-term assets	18,672	Long-term assets	18,989
Total asset derivatives		$ 102,280		$ 41,094
Liability derivatives not designated as hedges for accounting purposes:				
Interest rate contracts	Current liabilities	$ 7,086	Current liabilities	$ 8,623
Interest rate contracts	Long-term liabilities	10,164	Long-term liabilities	2,464
Total liability derivatives		$ 17,250		$ 11,087

ANTERO RESOURCES LLC

Notes to Consolidated Financial Statements (Continued)

December 31, 2007, 2008 and 2009

(11) Derivative Instruments (Continued)

The following is a summary of realized and unrealized gains (losses) on derivative instruments and where such values are recorded in the consolidated statements of operations for the years ended December 31, 2007, 2008, and 2009:

	Statement of operations location	2007	2008	2009
Realized gains on commodity contracts	Revenue	$ 14,373	26,053	116,550
Unrealized gains (losses) on commodity contracts	Revenue	4,619	90,301	(61,186)
Total gains on commodity contracts		18,992	116,354	55,364
Realized gains (losses) on interest rate contracts	Other income (expense)	400	(1,428)	(11,148)
Unrealized gains (losses) on interest rate contracts	Other income (expense)	(3,433)	(13,817)	6,163
Total losses on rate contracts		(3,033)	(15,245)	(4,985)
Net gains on derivative contracts		$ 15,959	101,109	50,379

The following table summarizes the valuation of investments and financial instruments by the fair value hierarchy described in note 1 at December 31, 2009:

	Fair value measurements using			
Description	Quoted prices in active markets for identical assets (Level 1)	Significant other observable inputs (Level 2)	Significant unobservable inputs (Level 3)	Total
	(In thousands)			
Derivatives asset (liability):				
Fixed price commodity swaps	$ —	41,094	—	41,094
Interest rate swaps	—	(11,087)	—	(11,087)
	$ —	30,007	—	30,007

(12) Income Taxes

Antero Resources LLC and each of its operating subsidiaries file separate federal and state income tax returns. Antero Resources LLC is a partnership for income tax purposes and therefore is not subject to federal or state income taxes. The subsidiaries of Antero Resources LLC are corporations subject to federal and state income taxes. The subsidiaries have not been in an income tax paying situation for the years ended December 31, 2007, 2008, or 2009.

ANTERO RESOURCES LLC

Notes to Consolidated Financial Statements (Continued)

December 31, 2007, 2008 and 2009

(12) Income Taxes (Continued)

The income tax expense (benefit) differs from the amount that would be computed by applying the U.S. statutory federal income tax rate of 34% to consolidated income for the years ended December 31, 2007, 2008, and 2009, respectively, as a result of the following (in thousands):

	2007	2008	2009
Federal income tax (benefit)	$ (12,972)	29,481	(37,107)
State income tax, net of federal benefit	(1,257)	2,376	(3,920)
Change in tax rate	(1,546)	760	—
Change in valuation allowance	15,360	(29,631)	40,504
Other	15	43	(2,082)
Total income tax expense (benefit)	$ (400)	3,029	(2,605)

Deferred income taxes reflect the impact of temporary differences between amounts of assets and liabilities for financial reporting purposes and such amounts as measured by tax laws. The tax effect of the temporary differences giving rise to net deferred tax assets and liabilities at December 31, 2008 and 2009 are as follows (in thousands):

	2008	2009
Deferred tax assets:		
Net operating loss carryforwards	$ 58,054	103,846
Unrealized losses on derivative instruments	1,063	649
Other	121	1,640
Total deferred tax assets	59,238	106,135
Valuation allowance	(6,449)	(46,952)
Net deferred tax assets	52,789	59,183
Deferred tax liabilities:		
Stock-based compensation	1,836	—
Unrealized gains on derivative instruments	34,000	11,984
Depreciation differences on gathering system	6,676	14,437
Sale of noncontrolling interest in subsidiary	2,690	—
Oil and gas properties	10,616	33,186
Total deferred tax liabilities	55,818	59,607
Net deferred tax liabilities	$ (3,029)	(424)

In assessing the realizability of deferred tax assets, management considers whether some portion or all of the deferred tax assets will be realized based on a more likely than not standard of judgment. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during the periods in which those temporary differences become deductible. Management considers the scheduled reversal of deferred tax liabilities, projected future taxable income, and tax planning strategies in making this assessment. Due to the lack of historical profitable operations and based upon the projections for future taxable income over the periods in which the deferred tax assets are deductible, management believes that the Company will not realize the benefits of all of these

ANTERO RESOURCES LLC

Notes to Consolidated Financial Statements (Continued)

December 31, 2007, 2008 and 2009

(12) Income Taxes (Continued)

deductible differences and has recorded a valuation allowance of approximately $47.0 million at December 31, 2009. The amount of the deferred tax asset considered realizable could be reduced in the near term if estimates of future taxable income during the carryforward period are reduced.

The subsidiaries of Antero Resources LLC have net operating loss carryforwards as of December 31, 2009 as follows (in thousands):

	Antero Arkoma	Antero Piceance	Antero Midstream	Antero Pipeline	Antero Appalachian	Combined total
Net operating loss carryforward	$ 106,673	125,276	27,375	7,712	9,216	276,252

The net operating loss carryforwards expire beginning in 2024 and through 2029. The tax years 2006 through 2009 remain open to examination by the U.S. Internal Revenue Service. The Company and subsidiaries file tax returns with various state taxing authorities; these returns remain open to examination for tax years 2005 through 2009.

(13) Commitments and Contingencies

(a) Operating Leases

The Company has commitments under office lease agreements as follows (in thousands):

2010	$ 629
2011	578
2012	257
2013	100
	$ 1,564

Rent expense for lease agreements was approximately $297,000, $526,000, and $886,000 during the years ending December 31, 2007, 2008, and 2009, respectively.

(b) Firm Transportation Commitments

The Company has entered into a firm commitment to transport 20,000 MMbtu per day of the Company's net production from the Arkoma Basin for the period January 1, 2009 through August 31, 2012. In addition, the Company has entered into a firm commitment to transport 40,000 MMbtu per day of the Company's net production from the Arkoma Basin for the period April 1, 2009 (estimated start date) through March 31, 2016. The agreement has staggered start and termination dates. Commitments for 20,000 MMbtu start April 1, 2009 and terminate March 31, 2014. Commitments for 10,000 MMbtu start April 1, 2010 and terminate March 31, 2015. The remaining 10,000 MMbtu commitments start April 1, 2011 and terminate March 31, 2016.

The Company currently has a firm commitment for 40,000 MMbtu/d on the WIC pipeline from the Piceance Basin through September 2020. In addition, the Company has also entered a firm commitment to transport 25,000 MMbtu per day of its production from the Piceance Basin to the West Coast for the period from April 1, 2011 (estimated in-service date) through March 31, 2021.

ANTERO RESOURCES LLC

Notes to Consolidated Financial Statements (Continued)

December 31, 2007, 2008 and 2009

(13) Commitments and Contingencies (Continued)

The Company has a 39,700 MMbtu/d firm commitment from the Appalachian Basin on the Columbia pipeline through January 2017.

Based on the Company's forecasted production and estimates of current reserves, we believe our future production will be sufficient to meet our delivery commitments under these contracts.

(c) Drilling Rig Service Commitments

The Company has entered into contracts for the services of five rigs, which expire at various dates in 2010. Commitments under these agreements are approximately $9.7 million at December 31, 2009.

(d) Processing Commitment

The Company has entered into a firm processing commitment to process its natural gas from the Piceance Basin. The agreement guarantees the Company the ability to process 60,000 MMbtu/day through December 31, 2017. The Company is obligated to pay $0.05 per MMbtu whether or not it processes natural gas.

(e) Litigation

The Company is party to various legal proceedings and claims in the ordinary course of its business. The Company believes certain of these matters will be covered by insurance and that the outcome of other matters will not have a material adverse effect on its consolidated financial position, results of operations, or liquidity.

(14) Guarantor Subsidiaries

The following entities are guarantors of the Company's senior notes: Antero Resources LLC (the Parent Company), Antero Arkoma, Antero Piceance, Antero Midstream, Antero Pipeline, and Antero Appalachian (collectively, the Guarantor Companies). Each of the guarantees is full and unconditional and joint and several. The nonguarantor company is Centrahoma Processing LLC.

ANTERO RESOURCES LLC

Notes to Consolidated Financial Statements (Continued)

December 31, 2007, 2008 and 2009

(14) Guarantor Subsidiaries (Continued)

The condensed consolidating financial statements below present the financial position, results of operations, and cash flows of Antero Resources LLC, its combined guarantor subsidiaries, and the nonguarantor company at December 31, 2008 and 2009. The combining condensed financial statements as of December 31, 2008 present the financial position, results of operations and cash flows of the combined guarantor Antero Entities and the nonguarantor company. There were no nonguarantor companies for the year ended December 31, 2007.

Condensed Combining Balance Sheet
December 31, 2008

	Guarantor companies	Nonguarantor company	Eliminations	Total
		(In thousands)		
Assets				
Cash and cash equivalents	$ 34,182	4,787	—	38,969
Accounts receivable	49,571	3,752	—	53,323
Derivative instruments	83,608	—	—	83,608
Other current assets	34,090	652	(6,474)	28,268
Total current assets	201,451	9,191	(6,474)	204,168
Property and equipment—net	1,727,452	70,263	—	1,797,715
Derivative instruments	18,672	—	—	18,672
Other assets, net	6,872	1,540	—	8,412
Total assets	$ 1,954,447	80,994	(6,474)	2,028,967
Liabilities and Equity				
Accounts payable and accrued expenses	$ 159,588	2,054	—	161,642
Revenue distribution payable and advances from joint interest owners	32,682	6,674	—	39,356
Derivative instruments	7,086	—	—	7,086
Other current liabilities	6,599	—	(6,474)	125
Total current liabilities	205,955	8,728	(6,474)	208,209
Long-term liabilities:				
Bank credit facility and term notes	621,580	—	—	621,580
Derivative instruments	10,164	—	—	10,164
Other long term liabilities	11,459	—	—	11,459
Total liabilities	849,158	8,728	(6,474)	851,412
Total equity	1,105,289	72,266	—	1,177,555
Total liabilities and equity	$ 1,954,447	80,994	(6,474)	2,028,967

ANTERO RESOURCES LLC

Notes to Consolidated Financial Statements (Continued)

December 31, 2007, 2008 and 2009

(14) Guarantor Subsidiaries (Continued)

Condensed Combining Income Statement
Year ended December 31, 2008

	Guarantor companies	Nonguarantor company	Eliminations	Total
		(In thousands)		
Revenue:				
Total revenue	$ 364,607	6,648	(4,765)	366,490
Operating expenses:				
Operating expenses	87,795	2,744	(4,765)	85,774
Depletion, depreciation and amortization	120,751	4,246	—	124,997
General and administrative	15,793	378	—	16,171
Total operating expenses	224,339	7,368	(4,765)	226,942
Operating income (loss)	140,268	(720)	—	139,548
Interest and other income (expense), net	(52,839)	—	—	(52,839)
Income before taxes	87,429	(720)	—	86,709
Current tax (expense) benefit	(3,029)	—	—	(3,029)
Net income (loss)	84,400	(720)	—	83,680
Noncontrolling interest in net loss of consolidated subsidiary	276	—	—	276
Net income (loss) attributable to Antero stockholders	$ 84,676	(720)	—	83,956

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ANTERO RESOURCES LLC

Notes to Consolidated Financial Statements (Continued)

December 31, 2007, 2008 and 2009

(14) Guarantor Subsidiaries (Continued)

Condensed Combining Statement of Cash Flows
Year ended December 31, 2008

	Guarantor companies	Nonguarantor company	Eliminations	Total
		(In thousands)		
Net cash provided by operating activities	$ 152,649	4,866	—	157,515
Net cash used in investing activities	(990,216)	(13,794)	—	(1,004,010)
Net cash provided by financing activities	860,635	13,715	—	874,350
Net increase in cash and cash equivalents	23,068	4,787	—	27,855
Cash and cash equivalents, beginning of year	11,114	—	—	11,114
Cash and cash equivalents, end of year	$ 34,182	4,787	—	38,969

ANTERO RESOURCES LLC

Notes to Consolidated Financial Statements (Continued)

December 31, 2007, 2008 and 2009

(14) Guarantor Subsidiaries (Continued)

Condensed Consolidating Balance Sheet
December 31, 2009

	Parent company	Guarantor companies	Nonguarantor company	Eliminations	Total
			(In thousands)		
Assets					
Cash and cash equivalents	$ —	9,090	1,579	—	10,669
Accounts receivable	—	23,795	12,102	—	35,897
Derivative instruments	—	22,105	—	—	22,105
Other current assets	—	35,218	599	(9,644)	26,173
Total current assets	—	90,208	14,280	(9,644)	94,844
Property and equipment—net	—	1,734,138	69,381	—	1,803,519
Derivative instruments	—	18,989	—	—	18,989
Other assets, net	—	17,673	1,541	—	19,214
Investment in subsidiaries	1,299,107	—	—	(1,299,107)	—
Total assets	$ 1,299,107	1,861,008	85,202	(1,308,751)	1,936,566
Liabilities and Equity					
Accounts payable and accrued expenses	$ —	72,168	866	—	73,034
Revenue distribution payable and advances from joint interest owners	—	30,704	—	—	30,704
Derivative instruments	—	8,623	—	—	8,623
Other current liabilities	—	(1,283)	11,059	(9,644)	132
Total current liabilities	—	110,212	11,925	(9,644)	112,493
Long-term liabilities:					
Bank credit facility and senior notes	—	514,477	—	—	514,477
Derivative instruments	—	2,464	—	—	2,464
Other long term liabilities	—	8,025	—	—	8,025
Total liabilities	—	635,178	11,925	(9,644)	637,459
Total equity	1,299,107	1,225,830	73,277	(1,299,107)	1,299,107
Total liabilities and equity	$ 1,299,107	1,861,008	85,202	(1,308,751)	1,936,566

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ANTERO RESOURCES LLC

Notes to Consolidated Financial Statements (Continued)

December 31, 2007, 2008 and 2009

(14) Guarantor Subsidiaries (Continued)

Condensed Consolidating Income Statement

Year ended December 31, 2009

	Parent company	Guarantor companies	Nonguarantor company	Eliminations	Total
			(In thousands)		
Revenue:					
Total revenue	$ —	205,749	9,585	(7,344)	207,990
Operating expenses: Operating expenses	—	116,513	6,264	(7,344)	115,433
Depletion, depreciation and amortization	—	136,058	3,755	—	139,813
General and administrative	—	20,370	473	—	20,843
Total operating expenses	—	272,941	10,492	(7,344)	276,089
Operating income (loss)	—	(67,192)	(907)	—	(68,099)
Interest and other income (expense), net	—	(41,038)	—	—	(41,038)
Equity in earnings (loss) of subsidiaries	(106,169)	—	—	106,169	—
Income before taxes	(106,169)	(108,230)	(907)	106,169	(109,137)
Income tax benefit	—	2,605	—	—	2,605
Net income (loss)	(106,169)	(105,625)	(907)	106,169	(106,532)
Noncontrolling interest in net loss of consolidated subsidiary	—	363	—	—	363
Net income (loss) attributable to Antero stockholders	$ (106,169)	(105,262)	(907)	106,169	(106,169)

ANTERO RESOURCES LLC

Notes to Consolidated Financial Statements (Continued)

December 31, 2007, 2008 and 2009

(14) Guarantor Subsidiaries (Continued)

Condensed Consolidating Statement of Cash Flows

Year ended December 31, 2009

	Parent company	Guarantor companies	Nonguarantor company	Eliminations	Total
			(In thousands)		
Net cash provided by operating activities	$ —	151,775	(2,468)	—	149,307
Net cash used in investing activities	(123,561)	(155,275)	(3,063)	—	(281,899)
Net cash provided by financing activities	123,561	101,969	2,323	(123,561)	104,292
Net increase in cash and cash equivalents	—	98,469	(3,208)	(123,561)	(28,300)
Cash and cash equivalents, beginning of year	—	34,182	4,787	—	38,969
Cash and cash equivalents, end of year	$ —	132,651	1,579	(123,561)	10,669

(15) Supplemental Information on Oil and Gas Producing Activities (Unaudited)

The following is supplemental information regarding our consolidated oil and gas producing activities. The amounts shown include our net working and royalty interests in all of our oil and gas properties.

(a) Capitalized Costs Relating to Oil and Gas Producing Activities

	Year ended December 31	
	2008	2009
	(In thousands)	
Producing properties	$ 1,148,306	1,340,827
Unproved properties	649,605	596,694
	1,797,911	1,937,521
Accumulated depreciation and depletion	(167,964)	(297,694)
Net capitalized costs	$ 1,629,947	1,639,827

ANTERO RESOURCES LLC

Notes to Consolidated Financial Statements (Continued)

December 31, 2007, 2008 and 2009

(15) Supplemental Information on Oil and Gas Producing Activities (Unaudited) (Continued)

(b) Costs Incurred in Certain Oil and Gas Activities

	Year ended December 31		
	2007	2008	2009
		(In thousands)	
Proved property acquisition costs	$ 29,074	3,466	1,029
Unproved property acquisition costs	144,897	457,879	16,118
Development costs and other	335,465	512,112	258,520
Asset retirement obligation	813	1,518	188
Total costs incurred	$ 510,249	974,975	275,855

(c) Results of Operations for Oil and Gas Producing Activities

	Year ended December 31		
	2007	2008	2009
		(In thousands)	
Revenues	$ 67,724	229,715	129,621
Production expenses	13,684	44,998	41,582
Exploration expenses	17,970	22,998	10,228
Depreciation and depletion expense	44,100	116,906	130,128
Impairment	4,995	10,112	54,204
	(13,025)	34,701	(106,521)
Income tax (expense) benefit	400	(3,029)	2,605
Results of operations	$ (12,625)	31,672	(103,916)

(d) Oil and Gas Reserves

The following table sets forth the net quantities of proved reserves and proved developed reserves during the periods indicated. This information includes the oil and gas segment's royalty and net working interest share of the reserves in oil and gas properties. "Prepared" reserves are those quantities of reserves that were prepared by an independent petroleum consultant. "Audited" reserves are those quantities of reserves that were estimated by Antero employees and audited by an independent petroleum consultant. Net proved oil and gas reserves for the three years ended December 31, 2009 were prepared by DeGolyer and MacNaughton, Ryder Scott, and Wright & Company utilizing data compiled by us. All reserves are located in the United States. There are many uncertainties inherent in estimating proved reserve quantities, and projecting future production rates and timing of future development costs. In addition, reserve estimates of new discoveries are more imprecise than those of properties with a production history. Accordingly, these estimates are subject to change as additional information becomes available. Proved reserves are the estimated quantities of crude oil, condensate, and natural gas that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known oil and gas reservoirs under existing economic and operating conditions at the end of the respective years. Proved developed reserves are

(15) Supplemental Information on Oil and Gas Producing Activities (Unaudited) (Continued)

those reserves expected to be recovered through existing wells with existing equipment and operating methods.

In December 2008, the SEC adopted revisions to its oil and gas reserve reporting requirements to modify their rules for modernization of oil and gas development technology and to change the rules for pricing oil and gas reserves. In January 2010, the FASB issued Accounting Standards Update 2010-03, "*Oil and Gas Reserve Estimation and Disclosures*", to provide consistency with the SEC rules.

In accordance with these new rules, as of December 31, 2009, the Company changed its definition of proved undeveloped reserves to include development spacing areas surrounding productive wells that are reasonably certain of containing proved reserves and which are scheduled to be drilled within five years from December 31, 2009 under the Company's development plans. Prior to December 31, 2009, proved undeveloped reserves included only one offsetting development spacing area from a productive well. Additionally, the Company estimated proved reserves using 12 month average pricing as of December 31, 2009 as required by the rules. Previously, rules required the use of year end pricing. The Company's development plans related to scheduled drilling over the next five years are subject to many uncertainties and variables, including availability of capital; future oil and gas prices; and cash flows from operations, future drilling costs, demand for natural gas, and other economic factors.

Additionally, in order to be more consistent with industry practice and to more reasonably estimate future reserves, the Company changed its method of estimating proved reserves to include reserves from properties having a positive net estimated future cash flow using a zero discount rate (PV-0) as opposed to its practice in prior years' reserves estimation methodology of including properties within its proved reserves only if their cash flow was positive using a discount rate of 10% (PV-10). The effect of this change in estimate was to increase reserves by approximately 138 Bcf at December 31, 2009 and is included in extensions, discoveries, and other additions in the following table for the year ended December 31, 2009. The change had no effect on how the Company computes depreciation and

ANTERO RESOURCES LLC

Notes to Consolidated Financial Statements (Continued)

December 31, 2007, 2008 and 2009

(15) Supplemental Information on Oil and Gas Producing Activities (Unaudited) (Continued)

depletion expense, as it has consistently used reserves calculated at PV-0 for purposes of units-of-production depreciation and depletion calculations.

	Oil and condensate (MMBbl)	Natural gas (Bcf)	Total equivalents (Bcfe)
Proved developed and undeveloped reserves:			
January 1, 2007	0.4	84.9	87.0
Revisions	—	(12.8)	(12.6)
Extensions, discoveries and other additions	0.6	164.7	168.6
Production	—	(10.9)	(11.2)
Purchase of reserves	—	2.9	2.9
Sale of reserves in place	—	—	—
December 31, 2007	1.0	228.8	234.7
Revisions	(0.5)	(2.5)	(5.5)
Extensions, discoveries and other additions	0.7	470.1	474.6
Production	—	(30.3)	(30.3)
Purchase of reserves	—	6.1	6.1
Sale of reserves in place	—	—	—
December 31, 2008	1.2	672.2	679.6
Revisions	0.5	(133.9)	(130.9)
Extensions, discoveries and other additions	0.1	627.2	627.8
Production	(0.1)	(35.2)	(35.8)
Purchase of reserves	—	—	—
Sale of reserves in place	—	—	—
December 31, 2009	1.7	1,130.3	1,140.7

	Oil and condensate (MMBbl)	Natural gas (Bcf)	Total equivalents (Bcfe)
Proved developed reserves:			
December 31, 2006	0.1	38.0	38.9
December 31, 2007	0.4	106.6	109.1
December 31, 2008	0.3	236.9	238.7
December 31, 2009	0.7	271.7	275.8

ANTERO RESOURCES LLC

Notes to Consolidated Financial Statements (Continued)

December 31, 2007, 2008 and 2009

(15) Supplemental Information on Oil and Gas Producing Activities (Unaudited) (Continued)

Significant items included in the categories of proved developed and undeveloped reserve changes for the years 2007, 2008, and 2009 in the above table include:

- *Extensions and Discoveries*—The additions to the Company's proved reserves through new discoveries and extensions result from (i) extensions of the proved acreage of previously discovered reservoirs through additional drilling of development wells and (ii) discovery of new fields with proved reserves through drilling of exploratory wells.

    - 2007—Our successful drilling in the Arkoma and Piceance Basin extended the proved acreage in those areas. As a result of these successes, we accelerated our forecasted drilling plans by approximately $106 million. Of the 168.6 Bcfe of 2007 extensions and discoveries, 42.6 Bcfe related to the Arkoma Basin and 126.0 Bcfe related to the Piceance Basin.

    - 2008—Of the 474.6 Bcfe of 2008 extensions and discoveries, 265.2 Bcfe related to the Arkoma Basin, 197.7 Bcfe related to the Piceance Basin, and 11.7 Bcfe related to our other areas. The increase in extensions and discoveries is the result of our drilling exceeding expected 2008 future drilling costs by $115 million.

    - 2009—Of the 627.8 Bcfe of 2009 extensions and discoveries, 280.0 Bcfe related to the Arkoma Basin in Oklahoma, 199.9 Bcfe related to the Piceance Basin in Colorado, 116.6 Bcfe related to the Appalachia Basin in Pennsylvania and West Virginia, and 31.3 related to our other areas. The increase in extensions and discoveries is the result of entering into the Marcellus Shale play in the Appalachia Basin, drilling exceeding expected 2009 future drilling costs by $173 million, and the change in estimating proved reserves.

- *Revisions Other Than Price*—The 2007 total included performance revisions primarily in the Arkoma Basin.

The following table sets forth the standardized measure of the discounted future net cash flows attributable to our proved reserves. Future cash inflows as of December 31, 2009 were computed by applying historical 12-month unweighted first-day of the month average prices. Future cash inflows as of December 31, 2007 and 2008 were computed by applying year-end prices of oil and gas to estimated future production of proved reserves. The estimated effect of this change in the method of pricing proved reserves was to decrease the standardized measure of the discounted future net cash flows attributable to our proved reserves by approximately $1.2 billion at December 31, 2009. Future prices actually received may materially differ from current prices or the prices used in the standardized measure.

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Notes to Consolidated Financial Statements (Continued)

December 31, 2007, 2008 and 2009

(15) Supplemental Information on Oil and Gas Producing Activities (Unaudited) (Continued)

Future production and development costs represent the estimated future expenditures (based on current costs) to be incurred in developing and producing the proved reserves, assuming continuation of existing economic conditions. Future income tax expenses were computed by applying statutory income tax rates to the difference between pretax net cash flows relating to our proved reserves and the tax basis of proved oil and gas properties. In addition, the effects of statutory depletion in excess of tax basis, available net operating loss carryforwards, and alternative minimum tax credits were used in computing future income tax expense. The resulting annual net cash inflows were then discounted using a 10% annual rate.

	Year ended December 31		
	2007	2008	2009
		(In millions)	
Future cash inflows	$ 1,549	2,931	3,571
Future production costs	(303)	(599)	(820)
Future development costs	(273)	(637)	(1,389)
Future net cash flows before income tax	973	1,695	1,362
Future income tax expense	(162)	(268)	(60)
Future net cash flows	811	1,427	1,302
10% annual discount for estimated timing of cash flows	(379)	(738)	(1,067)
Standardized measure of discounted future net cash flows	$ 432	689	235

The 12-month weighted average prices for the year ended December 31, 2009 and the year-end spot prices used to estimate the Company's total equivalent reserves were as follows:

	Arkoma	Piceance	Appalachia
		per MMbtu	
December 31, 2006 (spot price)	$ 5.27	4.46	—
December 31, 2007 (spot price)	6.22	6.04	—
December 31, 2008 (spot price)	4.61	4.61	—
December 31, 2009 (average price)	3.25	3.07	4.15

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Notes to Consolidated Financial Statements (Continued)

December 31, 2007, 2008 and 2009

(15) Supplemental Information on Oil and Gas Producing Activities (Unaudited) (Continued)

(e) Changes in Standardized Measure of Discounted Future Net Cash Flows

	Year ended December 31		
	2007	2008	2009
	(In millions)		
Sales of oil and gas, net of productions costs	$ (51)	(177)	(205)
Net changes in prices and production costs	48	(152)	(257)
Development costs incurred during the period	106	115	7
Net changes in future development costs	(12)	(126)	(239)
Extensions, discoveries and other additions	270	533	223
Revisions of previous quantity estimates	(25)	(8)	(42)
Accretion of discount	18	70	62
Net change in income taxes	4	(33)	(50)
Other changes	(16)	35	47
Net increase (decrease)	342	257	(454)
Beginning of year	90	432	689
End of year	$ 432	689	235

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